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The Canadian Oil Market

Vol. VI, No 1, Spring 1990

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THE ENERGY OF OUR RESOURCES

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THE CANADIAN OIL MARKET

Vol. VI, No. 1, Spring 1990

Canadian Oil Markets and Emergency Planning Division
Energy Sector
Energy, Mines and Resources Canada

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The Canadian Oil Market

Overview

The contraction in domestic oil supply and demand, that began early in 1989, continued in the first quarter of 1990. The contraction reflected both the general economic slowdown and problems specific to the oil industry.

Drilling activity, after a year of being in a severe slump, showed little sign of recovery in the first quarter, despite the fact that midway through the quarter crude oil prices briefly reached their highest level since early 1986. Past oil price instability, high royalty and interest rates, company mergers, and the failure in recent years to discover any substantial pools in the Western basin have all been suggested as reasons underlying the decline in Canadian oil exploration and development. One of the consequences has been a fall in productive capacity in the conventional oil sector. The situation has been exacerbated by the focus of recent drilling activity on the search for natural gas rather than crude oil.

Against a backdrop of declining productivity in the conventional sector, a sharp downturn in synthetic crude production occurred during the first quarter in the wake of a major explosion and fire at Syncrude in December of 1989. This more than halved production at the plant during January and February. In fact, during the first two months of 1990 domestic crude oil supply fell by almost 20 000 m^3/d on a year-over year basis, with over half of the decline attributable to the production disruption at Syncrude.

Just as domestic supply was dropping, Canadian refiners were increasing their demand for crude oil to accommodate an unusually high level of crude runs during the quarter. The increase in refinery throughput was meant to build refined product inventories prior to a spate of refinery turnarounds scheduled for the second quarter. The combination of increased crude oil demand on the one hand, and lower supply on the other, contributed to a sharply reduced quarterly crude oil trade surplus. Crude oil exports fell by about 9 000 m^3/d from last year, while imports climbed by almost 15 000 m^3/d. In fact, in February, Canada found itself running a trade deficit in crude oil of approximately 16 000 m^3/d. The February deficit reflected not only lower output at Syncrude but also Atlantic refiners' efforts to rebuild inventories of imported crude oil after they had fallen to unusually low levels in January.

Canada's slim crude oil trade surplus might well have been eliminated entirely had domestic refined product consumption remained at last year's level. However, demand for refined products has also been in a state of decline after having peaked in the first quarter of 1989. Sales were down 2%, or almost 5 000 m^3/d, from last year, reflecting higher product prices and the virtual absence of economic growth during the quarter.

A new section covering the quarterly financial performance of the Canadian petroleum industry has been added to the Canadian Oil Market Report. Highlights of the financial review, prepared by the Petroleum Monitoring Agency, are as follows:

- *Industry's internal cash flow in the first quarter of 1990 decreased by 9% to $1.8 billion year-over-year, as a $1 billion increase in expenditures more than offset an additional $800 million in revenues.*
- *Net income , after unusual items, fell 13% to $500 million, and dividend payments declined 44% to $225 million.*
- *During the first quarter, gross capital expenditures increased by 5% to $1.6 billion, raising the reinvestment rate to 84% from 73% last year.*

1. Refined Product Consumption

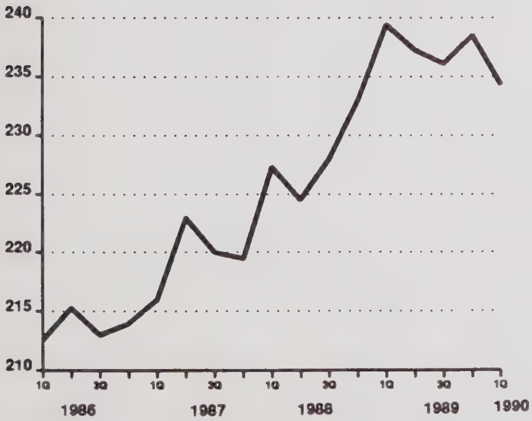
- *The downward trend in seasonally adjusted refined product sales re-emerged in the first quarter after a temporary interruption in the previous quarter, reflecting the lack of growth in the economy and a relatively warm weather.*

- *All regions recorded lower product sales, with two-thirds of the total decline occurring in the Quebec and Atlantic regions.*

1.1 Seasonally Adjusted Refined Petroleum Product Demand

Seasonally adjusted consumption of refined petroleum products (see definition in glossary) averaged 234 000 m^3/d during the first quarter of 1990. This spelled a resumption of the gradual downward trend in product demand that emerged last year, following several years of steady growth (see figure below). The decline in sales, however, had been temporarily interrupted in the fourth quarter of 1989 when unseasonably cold weather in eastern Canada resulted in a surge in demand for fuel oil. The prevailing weakness in the refined product markets largely reflects the current economic slowdown (there was virtually no economic growth in the first quarter); and, to a lesser extent, higher product prices (up about 5 to 10% from last year), which in part reflected the steep climb in crude costs that began in the final quarter of 1989 and continued through much of the first quarter.

Figure 1.1
Total Refined Product Consumption
(Seasonally Adjusted at Annual Rates)
000 m^3/d



Total refined product sales, on a seasonally adjusted basis, declined 1% or almost 3 000 m^3/d in the first quarter from the average annual level recorded last year. 'Other' products showed the largest relative decline, with sales down 8% from the 1989 level, to 43 000 m^3/d. Heating oil sales fell 2% to 20 000 m^3/d, reflecting relatively warm weather in eastern Canada where most heating oil is sold. Heavy fuel oil, which in recent years has accounted for much of the gains made in total product sales, held steady at 27 000 m^3/d. Motor gasoline and diesel fuel sales, on the other hand, both rose marginally, to 96 000 m^3/d and 48 000 m^3/d, respectively. It is interesting to note that while gasoline demand has remained virtually flat in recent years, diesel fuel consumption has followed an upward trend such that volumetrically, diesel sales are now at about half the level of gasoline.

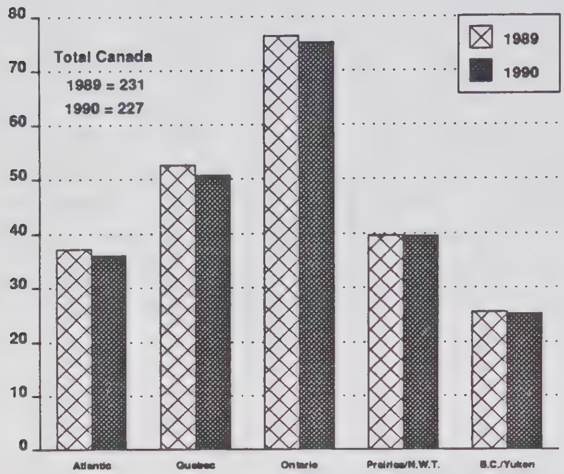
1.2 Regional Demand

Actual consumption (before seasonal adjustments) in Canada averaged 227 000 m^3/d during the first quarter, down 2% or close to 5 000 m^3/d from the same quarter last year. With the exception of diesel fuel which saw a marginal increase in demand, all product categories recorded lower sales, ranging from a 1% drop for heavy fuel oil to 6% for 'other' products.

Product sales fell across Canada. In the Atlantic, sales fell 3% with a 12% decline in heavy fuel oil more than offsetting a 5% increase in middle distillate demand. The Atlantic region accounted for 16% of product sales in Canada.

In Quebec, which currently accounts for about 22% of total Canadian refined product consumption, sales fell by almost 4%. 'Other' products recorded a 15% decline, and heating oil sales were 10% lower than last year. Heavy fuel oil demand, however, was up 9% largely as a result of the re-activation of the Tracy thermal electric plant last year. At peak capacity utilization, the Tracy plant would require 4 000 m^3/d of heavy fuel oil. The plant was re-activated to help offset a shortfall in hydro-generation stemming from low water levels.

Figure 1.2
Regional Refined Product Consumption
(First Quarter)
000 m^3/d



About a third of all refined product sales occurred in Ontario. Ontario demand declined by less than 2%. Only heavy fuel oil made any substantive gains, with sales rising by almost 20% from last year. All other product categories recorded slight declines in sales. As in Quebec, much of the incremental demand for heavy fuel oil has come from the electric power industry. First quarter sales were further boosted in the industrial fuel-switchable market by heavy fuel oil's competitive price, and natural gas delivery constraints.

There was virtually no change in product consumption in the Prairies. Marginal increases in diesel fuel and heating oil sales were offset by equally marginal declines in the remaining products. Prairie sales comprised 17% of the Canada total.

Product demand in British Columbia also declined only marginally from last year. While heavy fuel oil and diesel demand grew modestly, declines were recorded in the other product categories. About 11% of Canadian product sales were in British Columbia.

1.3 OECD Oil Product Consumption

Overall oil demand by OECD (Organization of Economic Cooperation and Development) countries; at 38.5 MMB/D, was flat in the first quarter compared with 1989 levels. There were however, significant variations at the regional level. In North America, oil consumption actually declined by about 500 MB/D (2.8%), to 19 MMB/D. This was partly due to warm weather in January and February and a sluggish economy.

In Europe, oil consumption increased by about 200 MB/D, or 1.8%, to 13 MMB/D. This increase reflected the exceptionally mild winter which occurred in the previous year, while in Germany stocks were built to abnormally high levels in expectation of a January 1, 1989 tax increase.

In the OECD Pacific region, consumption continued to show substantial increases, up 4.9%, to 6.5 MMB/D. Japan's relatively strong economy remains the most significant factor behind the continued growth in oil demand.

On an individual petroleum product basis, first quarter motor gasoline sales in North America were unchanged from last year, at 7.7 MMB/D, while in Europe and the Pacific region sales were up 2.4% and 5.7% from year-ago levels, to 2.7 MMB/D and 1.1 MMB/D respectively. Likewise, middle distillate demand in North America fell 2.8%, to 3.7 MMB/D. In Europe and the Pacific region, however, distillate consumption increased 4.7% and 5.8% respectively, to 4.7 MMB/D and 2.2 MMB/D. Heavy fuel oil sales declined 11.7% in North America by 0.4% in Europe, to 1.7 MMB/D and 2.4 MMB/D, respectively. In the Pacific region, heavy fuel consumption increased by 1.4%, to 1.0 MMB/D.

OECD Petroleum Product Consumption
(First Quarter)
% Change Over Previous Year

	North America		OECD Europe		OECD Pacific		Total OECD	
	89/88	**90/89**	**89/88**	**90/89**	**89/88**	**90/89**	**89/88**	**90/89**
Motor Gasoline	1.7	-	3.5	2.4	3.1	5.7	2.2	1.1
Middle Distillates	(4.5)	(2.8)	(4.1)	4.7	3.0	5.8	(2.8)	2.2
Heavy Fuel Oil	3.3	(11.7)	6.5	(0.4)	3.1	1.4	4.5	4.0
Other Products	2.1	(3.7)	7.8	1.3	4.8	5.0	4.2	1.4
Total	**0.7**	**(2.8)**	**2.2**	**1.8**	**3.7**	**4.9**	**1.7**	**-**

2. Drilling and Exploration Activity

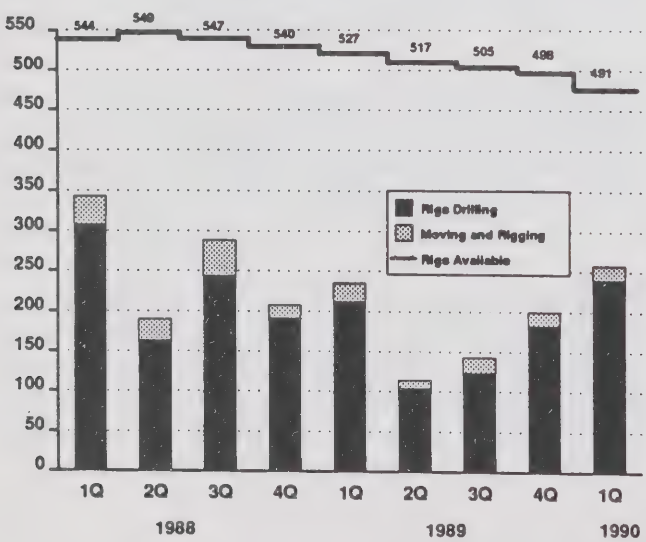
- *An anticipated turnaround in drilling rig activity failed to materialize as more than half of Western Canada's rigs remained idle during the first quarter of 1990.*

- *The industry forecasts an overall annual rig utilization rate only slightly above last year's record low of 30%.*

Another lacklustre year appears to be in the offing, as first-quarter drilling activity fell short of industry expectations. Analysts had forecast a modest 10 to 15% increase in rig activity this year over last - the worst year of the eighties for the Canadian drilling industry.

The 1990 annual rig utilization rate was forecast at 35% with a first-quarter rate of 53%. It appears unlikely that this annual forecast can be met given an actual first-quarter utilization rate of only 49%. For this forecast to be met, there would have to be a significant upturn in activity during the second quarter of this year. Early second-quarter drilling activity (April and May), disrupted by poor weather conditions, in fact, indicates a rate falling below that of last year.

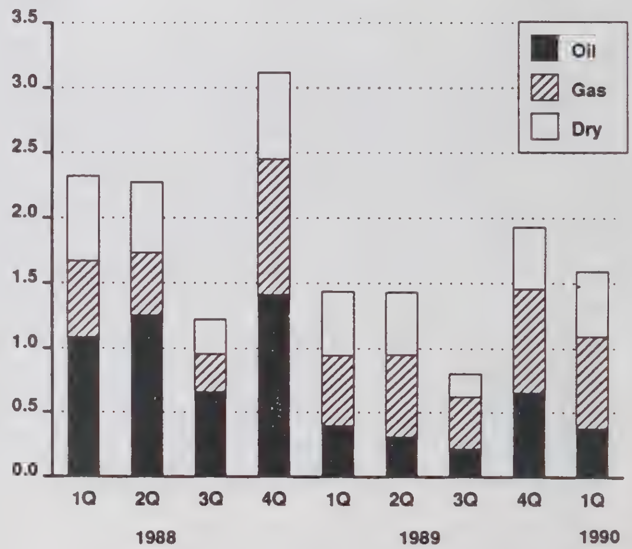
Figure 2.1
Drilling Rig Activity In Western Canada
(number of rigs)



The industry downturn is blamed on a number of factors including unstable oil prices, the strength of the Canadian dollar, high provincial royalty rates, and certain regulatory issues affecting natural gas transportation and exports. As well, the continuing impact of company mergers and acquisitions has redirected company spending away from drilling programs to asset management.

By the end of the first quarter, 1594 wells (of which 30% were dry) had been drilled, about 10% more than a year earlier. Most of the increase was the result of a 30% jump in natural gas well completions while oil completions fell by 5%. It is interesting to note that the average depth of a well drilled in Canada is reported to have decreased by nearly 59 metres, reflecting the large number of shallow gas wells being drilled.

Figure 2.2
Well Completions
(in thousands)



Drilling activity is expected to remain weak for the remainder of the year and a turnaround in the industry is thought to be still several years away. The Canadian Petroleum Association (CPA) suggests that high risk, high interest rates and high provincial royalties are discouraging oil exploration.

3. Crude Oil Supply

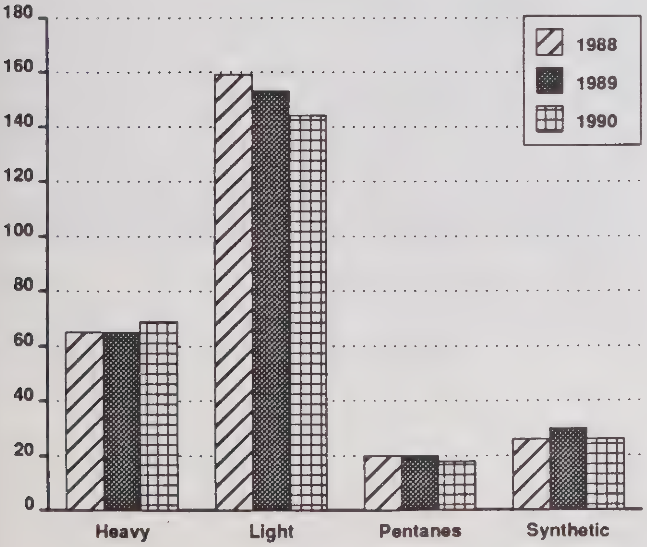
- *Western Canada is expected to produce 2% less crude oil in 1990 than last year due primarily to falling output from Alberta conventional oil fields.*
- *Crude oil imports, at 91 000 m^3/d, were unusually high during the first quarter.*
- *Total supply (domestic crude plus imports) available for delivery was 349 000 m^3/d.*

3.1 Domestic Crude Oil Production

Over the past two years, western Canadian production of crude oil and equivalent has declined by over 13 000 m^3/d. This drop was attributed to a number of factors, including declining oil prices, ever-smaller oil finds and the high risk and cost of oil exploration and development.

Total production of crude oil and equivalent in Canada during the first quarter of 1990 averaged about 258 000 m^3/d, 4% below the same period last year. As illustrated by figure 3.1.1 higher heavy crude oil production during the first quarter failed to offset a 9 000 m^3/d decrease in conventional light crude oil.

Figure 3.1.1
Crude Oil Production
(First Quarter)
000 m^3/d



Conventional light crude production declined by 6% to 144 000 m^3/d. Most of this drop was recorded in Alberta where production from conventional fields fell from 130 000 m^3/d to 120 000 m^3/d. This decrease, reported to be somewhat higher than expected, was the result of early spring road bans, refinery maintenance programs and high inventory levels. All other regions measured small changes in production levels.

Synthetic crude production averaged 26 000 m^3/d, 13% below the first quarter of last year. The lower rate of production was the result of damage to the Syncrude plant following a mid-December explosion and fire. By the end of March, Syncrude production had almost fully recovered fom a low of 10 000 m^3/d in January to 26 000 m^3/d, while Suncor production held at 9 000 m^3/d. No significant amount of synthetic crude produced by the Newgrade upgrader was sold to refineries other than Co-op.

Pentanes Plus supply, which may have been affected by the decline in crude oil production, decreased by 8% to 18 000 m^3/d. Less than one third of this volume was delivered as refinery feedstock while the remainder was used as heavy crude oil diluent.

Heavy crude oil and bitumen production (unblended) increased to 69 000 m^3/d, 6% above than the same period last year. This increase was attributed to higher conventional production (48 000 m^3/d), the result of modest drilling activity in the Bow River area of southeastern Alberta. Bitumen production declined marginally to 21 000 m^3/d, reflecting the postponement last year of several development projects pending higher and more stable crude oil prices .

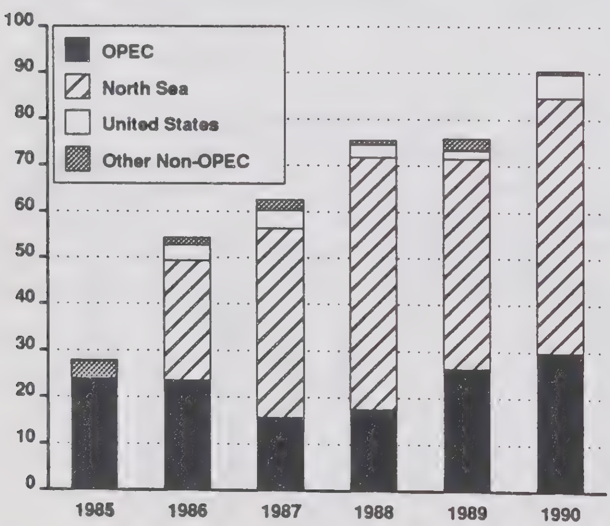
Total "shut-in" in the first quarter averaged 7 000 m^3/d, just below a year earlier but up 3 000 m^3/d from the previous quarter. This increase, despite the high demand for light and heavy crude and the absence of pipeline apportionment, was related to severe winter weather conditions in January and some early February pipeline equipment problems.

Based on recent National Energy Board estimates, total crude oil and equivalent production for the remainder of 1990 is expected to average 264 000 m^3/d, for an annual average of 262 000 m^3/d (2% below 1989). Conventional light crude production is expected to continue to decline as drilling activity levels are thought to be insufficient to offset declining production from existing large pools. Total synthetic crude output is expected to return to normal levels. Heavy (unblended) crude production, particularly from Alberta, is expected to show some growth offsetting small decreases in other heavy oil producing areas.

3.2 Crude Oil Imports by Source

Crude oil imports in the first quarter rose by 20% to almost 91 000 m^3/d relative to the same period a year ago. In fact, imports reached nearly 111 000 m^3/d in February, producing an unusual trade deficit in crude oil for the month of about 16 000 m^3/d. This surge in imports was largely attributable to Atlantic refiners' efforts to restore crude oil inventories after they had fallen to unusually low levels in January.

Figure 3.2.1
Imports of Crude Oil by Source
(First Quarter)
000 m^3/d



Foreign crudes made up 35% of total crude oil feedstock receipts in Canada, vis-a-vis 31% last year. Imports continued to be confined to eastern Canada, with western Canadian refineries relying completely on domestic crude oil feedstocks. In large measure, the rise in imports in central Canada was a manifestation of the decline in Canadian crude oil production that has re-emerged in the last year. The sharp drop in production at Syncrude was another factor. Although domestic refiners did increase their receipts of Canadian crude somewhat (at the expense of crude oil exports),it was however imports which accounted for 90% of the rise in refinery feedstocks in Canada.

The North Sea was the source for 61% of imports, with deliveries averaging about 55 000 m^3/d during the quarter. North Sea crudes comprised 90% of Quebec imports and 45% of Atlantic imports. OPEC, on the other hand, supplied 30 000 m^3/d or a third of the total. Over half of OPEC supply came from Saudi Arabia and Nigeria. About 90% of the OPEC crudes were shipped to Atlantic refineries with the remainder delivered to Quebec. Imports from Mexico, by and large of heavy crude oil, averaged close to 1 000 m^3/d. Crudes from the United States rose by almost 200%, reaching 5 000 m^3/d. These were delivered to Ontario refineries, in part to compensate for a temporary shortfall in synthetic crude oil supply.

3.3 Total Crude Oil Supply

With indigenous crude oil supply (which includes Ontario production, recycled diluent, and Newgrade's surplus production that is re-injected into the IPL system as light crude) estimated at 258 000 m^3/d during the first quarter, and crude imports at 91 000 m^3/d, the total available supply of crude oil in Canada amounted to about 349 000 m^3/d. About 28% of this crude oil supply was exported, with the remainder going to domestic refineries.

4. Crude Oil Disposition

- *Deliveries of crude oil to Canadian refineries increased by 7% to 258 000 m^3/d.*

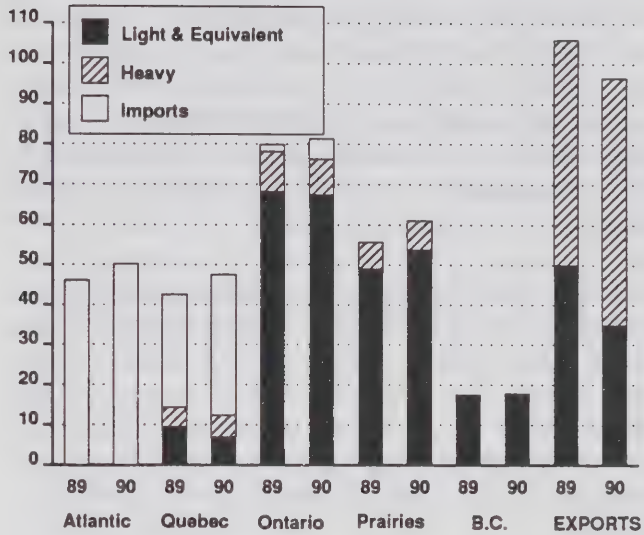
- *Exports during first quarter 1990 averaged 97 000 m^3/d, 9% less than last year.*

4.1 Canadian Refinery Crude Oil Receipts

Canadian refineries increased their receipts of crude oil by 7% on a year-over-year basis in the first quarter of 1990. Averaging 258 000 m^3/d over the quarter, receipts were almost 17 000 m^3/d higher than in the same quarter of 1989. This relatively sharp rise in receipts was necessary to accommodate higher crude runs, which were up 13 000 m^3/d from last year. The higher crude runs in turn were required to build refined product inventories in anticipation of significantly lower refinery production in the second quarter when a large number of refinery maintenance turnarounds were scheduled, particularly in Ontario. The higher level of this year's receipts also contributed to a build in crude oil inventories - in contrast to a drawdown which was the case last year.

Across Canada, receipts of domestic crude oil rose by less than 2 000 m^3/d to 168 000 m^3/d. They actually fell in eastern Canada where the shortfall was more than made up for by substantially higher crude oil imports. The latter rose by 15 000 m^3/d to approach 91 000 m^3/d. While Canadian refiners increased their demand for domestic light crude oil to 146 000 m^3/d, their intake of domestic heavy crude oil remained steady at last year's level of about 22 000 m^3/d. With the start-up of the Newgrade upgrader in Regina towards the end of 1988, it was expected that heavy crude oil receipts would have been 3 000 m^3/d to 4 000 m^3/d higher this year. However, because of a number of commissioning problems over the course of the last year, the 8 000 m^3/d upgrader has only been able to operate intermittently.

Figure 4.1
Disposition of Crude Oil
(First Quarter)
000 m^3/d



On a regional basis, Atlantic crude oil receipts, exclusively of foreign origin, were 4 000 m^3/d higher this year than last. The rise in receipts was largely reflective of Atlantic refinery processing agreements, rather than of regional product demand.

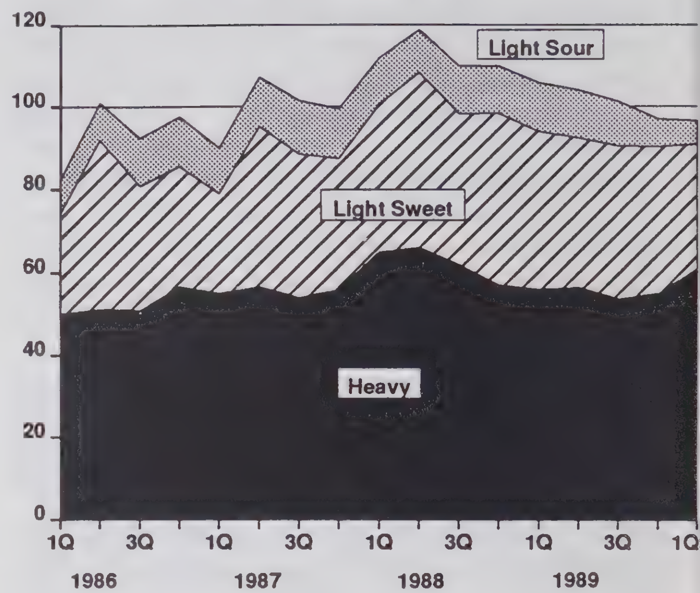
In Quebec, first quarter receipts were up 5 000 m^3/d from the year before. Domestic receipts fell 2000 m^3/d while imports rose by 7 000 m^3/d. Domestic crude receipts accounted for only 25% of the Quebec total versus a 34% share last year. Increasingly, Montreal refiners are choosing to import offshore crudes leaving the dwindling supplies of indigenous light crude oil to the landlocked refineries in Ontario and PAD District II.

Ontario refiners also increased their level of imports, which were comprised exclusively of U.S. crudes. Imports trebled to 5 000 m^3/d at the same time as domestic feedstock fell by 2 000 m^3/d, resulting in an overall increase in receipts of less than 2 000 m^3/d. The imports helped close a gap in domestic light crude oil supply that developed in the wake of the production disruption at Syncrude.

The problems at Syncrude do not appear to have had much impact on synthetic crude deliveries to Prairie refineries. Synthetic receipts were maintained at planned levels. Reflecting the re-activation of the Newgrade Upgrader after a six-month hiatus in the latter half of 1989, Prairie demand for heavy crude oil recovered in the first quarter, and rose by almost 1 000 m^3/d from the year before. In fact some of Newgrade's reconstituted crude was surplus to the adjacent refinery's requirements and so was delivered to Ontario. Overall crude oil demand in the Prairies rose by close to 6 000 m^3/d.

In British Columbia, crude oil receipts remained virtually unchanged from last year. B.C. refiners continue to rely entirely on domestic supplies to meet their crude oil requirements. The decline in crude oil receipts that has been observed in recent years has resulted from some limited substitution (currently about 5 000 m^3/d) of semi-refined oil pipelined from Edmonton to Vancouver-area refineries.

Figure 4.2.1
Crude Oil Exports
000 m^3/d



4.2 Canadian Crude Oil Exports

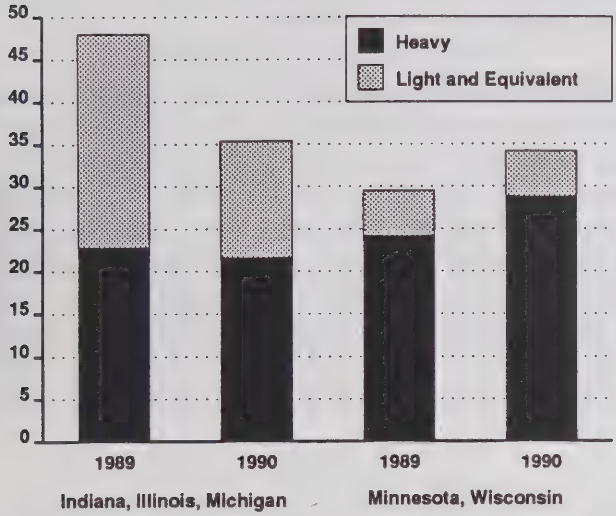
Total crude oil exports for the first quarter of 1990 averaged 97 000 m^3/d, 9% less than a year earlier. In fact, as illustrated by figure 4.2.1, exports have been on the decline since the second quarter of 1988, down by nearly 20% since that period. The slide in exports is attributed to a number of factors most notably the decline in conventional light crude oil production and increased Canadian demand for domestic heavy crude.

First-quarter exports of crude oil and equivalent represented about 37% of total domestic production, compared with 39% during the same period last year (79% of blended heavy supply and 20% of light production). Heavy crude exports supported by a modest rise in production and lower prices, increased by 10% to 62 000 m^3/d. Exports of light crude, 80% of which was light sweet, decreased by 30% to 35 000 m^3/d.

As illustrated in table 4.2, most Canadian crude oil exports were delivered to the United States, with small volumes of mainly heavy crude tankered offshore to South Korea and Taiwan. Most of the first-quarter decline occurred in U.S. PAD District II where total deliveries, when compared with a year earlier, dropped by 10% to nearly 70 000 m^3/d.

Slightly more than half of deliveries to PAD District II, as can be seen in figure 4.2.2, were concentrated in the Indiana, Illinois and Michigan refining area. Total first-quarter deliveries to this area, of which 44% were delivered to the Chicago Illinois market, averaged 35 000 m^3/d, down 26% from a year earlier. Light crude oil deliveries fell by 45% to 14 000 m^3/d.

Figure 4.2.2
Crude Oil Deliveries to PAD District II
By Refining District
(First Quarter)
000 m^3/d



While PAD District II recorded the largest drop in deliveries of Canadian crude, all other PAD Districts with the exception of PAD District III registered decreases. Exports to Canada's second largest market PAD District IV (the Montana and Wyoming area), averaged 11 000 m^3/d, slightly below a year earlier.

Since 1988, Canada's share of the total U.S. crude import requirements has fallen. According to U.S. Department of Energy and National Energy Board data, Canada's share of the U.S. import market has decreased to 10% from 13% in 1988. Nevertheless, Canada still remained the fourth largest supplier of imported crude behind Saudi Arabia, Nigeria and Mexico. As well, Canada's share of PAD District II's import requirements has dropped to 41% from 56%.

Crude oil exports for the second quarter of 1990, based on nominations filed with provincial authorities, are pegged at 95 000 m^3/d. This represents a 9% drop from the same period last year.

Table 4.2
Crude Oil Exports by Destination
(First Quarter)
000 m^3/d

U.S. PAD* Districts	Light		Heavy		Total	
	1989	1990	1989	1990	1989	1989
I	7.5	6.3	1.6	1.8	9.1	8.1
II	30.6	19.0	47.1	50.5	77.7	69.5
III	-	-	2.0	3.3	2.0	3.3
IV	8.5	9.0	3.3	2.3	11.8	11.3
V	2.9	0.7	0.4	0.8	3.3	1.5
Total U.S.	49.5	35.0	54.4	58.7	103.9	93.7
Offshore	0.4	0.4	1.6	2.5	2.0	2.9
Total Exports	**49.9**	**35.0**	**56.0**	**61.6**	**105.9**	**96.6**

* *U.S. Petroleum Administration For Defense (PAD) Districts*

5. Pipelines

- *The lower first quarter throughput on the two main pipelines reflected declining domestic crude oil production.*

- *Foreign crude oil receipts by Montreal refiners rose by about 4 500 m^3/d from last year, while domestic receipts fell by nearly 3 000 m^3/d.*

Western Canadian crude oil is, for the most part, delivered to markets through a network of pipelines. A map illustrating major crude oil pipelines in North America is shown below.

The Trans Mountain Pipe Line and the Interprovincial Pipe Line originate in Edmonton, where most Canadian crude oil is gathered. The Rangeland pipeline supplies a few U.S. refiners south of the Prairie provinces. The selected American pipelines shown on the map illustrate the supply alternatives for our main export market. Chicago can be supplied with US domestic crudes from Cushing, Oklahoma, with foreign crudes through the US Gulf (LOOP), and with Canadian crudes via the Interprovincial Pipeline.

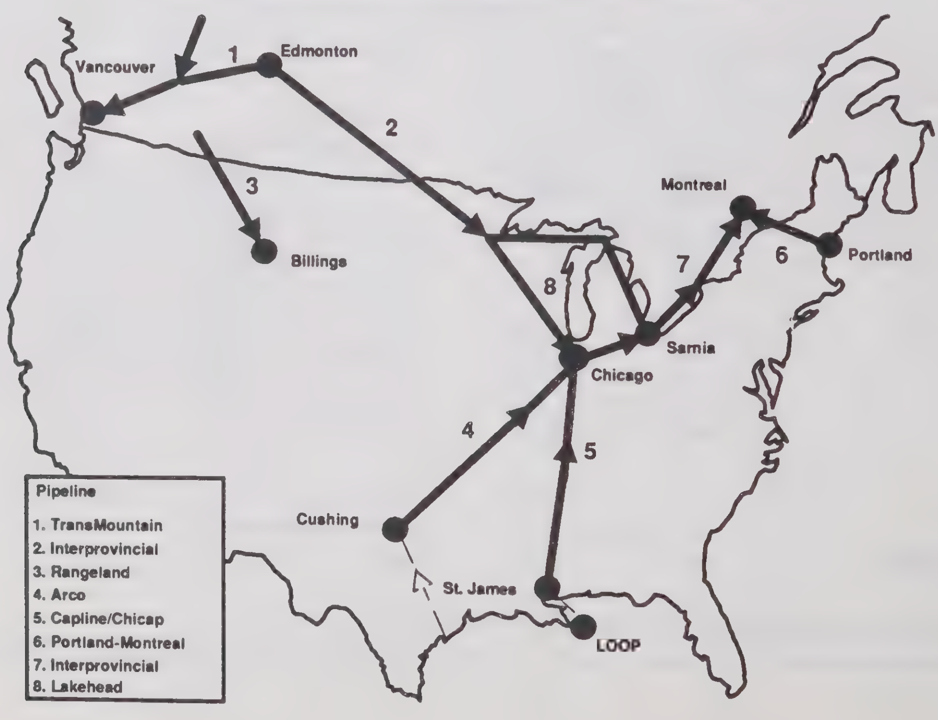
5.1 Trans Mountain Pipe Line

During the first quarter of 1990, Trans Mountain Pipe Line (TMPL) throughput averaged 26 600 m^3/d, down 8% from the previous quarter. Although TMPL completed a capacity expansion towards the end of 1989, the throughput for 1990 is expected to remain virtually unchanged from last year.

Total deliveries of crude oil to B.C. refineries during the first quarter were 13 700 m^3/d, 500 m^3/d lower than a year ago. Deliveries of semi-refined products also decreased by 500 m^3/d to 5 100 m^3/d. The reduced deliveries of refinery feedstocks were counterbalanced by substantially large closing inventories at the end of 1989, which permitted refinery throughput to be maintained at similar levels to a year ago. Deliveries of refined products from Edmonton to Kamloops B.C. remained relatively stable at 2 700 m^3/d during the quarter.

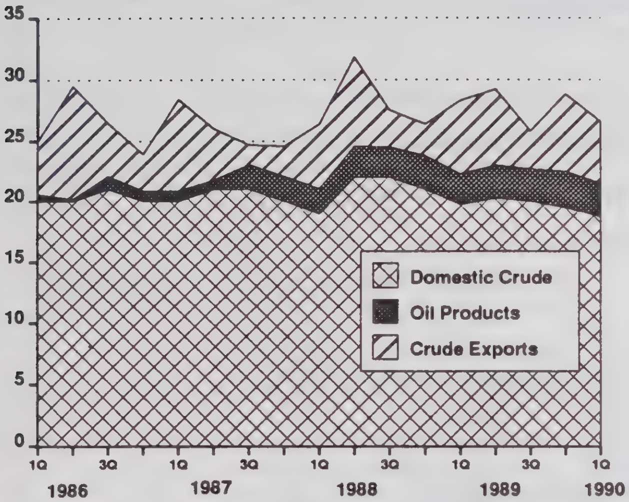
Crude oil deliveries for export, either at the Westridge marine terminal or the Puget Sound area, averaged 5 100 m^3/d, almost 1 000 m^3/d less than either the previous quarter or the same quarter a year ago. Tanker exports increased by 800 m^3/d from the previous quarter, while pipeline exports decreased by 1 700 m^3/d.

Figure 5.
Major Crude Oil Pipelines in North America



The basic toll applying to light crude oil deliveries from Edmonton to Burnaby, B.C. was $6.39/m^3. The National Energy Board approved new tolls, effective April 21, 1990. The new toll for light crude oil increased by $2.03/m^3 (32%) to $8.42/m^3.

Figure 5.1
Trans Mountain Deliveries
000 m^3/d



5.2 Interprovincial Pipe Line

The Interprovincial Pipe Line system consists of two connected segments, the first one is in Canada and is commonly referred to as IPL while the second, called "Lakehead", serves American markets in the Great Lakes area.

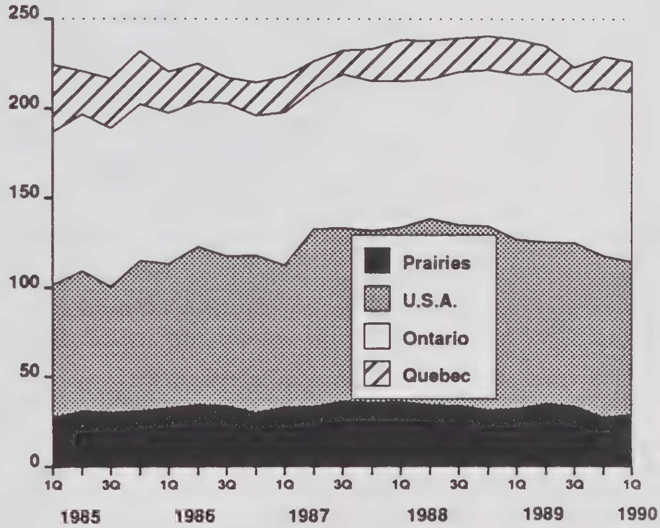
Total IPL and Lakehead deliveries of crude oil and other hydrocarbons, including petroleum products and natural gas liquids, during the first quarter of 1990, averaged 226 000 m^3/d, down 2 600 m^3/d from the previous quarter and 13 000 m^3/d from one year ago.

Total deliveries of crude oil to Canadian refineries during the first quarter were 141 000 m^3/d, 4 000 m^3/d (3%) less than a year earlier but 2 000 m^3/d higher than the fourth quarter of 1989. Deliveries to Canadian refiners represented 62% of IPL total throughput. Deliveries to the United States, at 85 700 m^3/d, were down about 10 000 m^3/d (9%) from the previous year.

The pipeline cost of delivering light crude oil from Edmonton to Toronto remained unchanged during the first quarter at about $8.15/m^3. New pipeline tolls and terminalling and tankage charges have been approved by the NEB effective April 1 through to the end of the year. The new tolls and charges represent a total increase of about $0.85/m^3 to about $9.03/m^3.

Changes to the tariff structure have also been introduced. Heavy crude movements are now subject to a surcharge of 20%, rather than 30%, over the base rate while medium crudes face a surcharge of 8% compared to 10% previously. The tariff applicable to very light products, such as gasoline and condensates, is now only 92% of the base rate versus 100% before.

Figure 5.2
Total IPL Deliveries
000 m^3/d

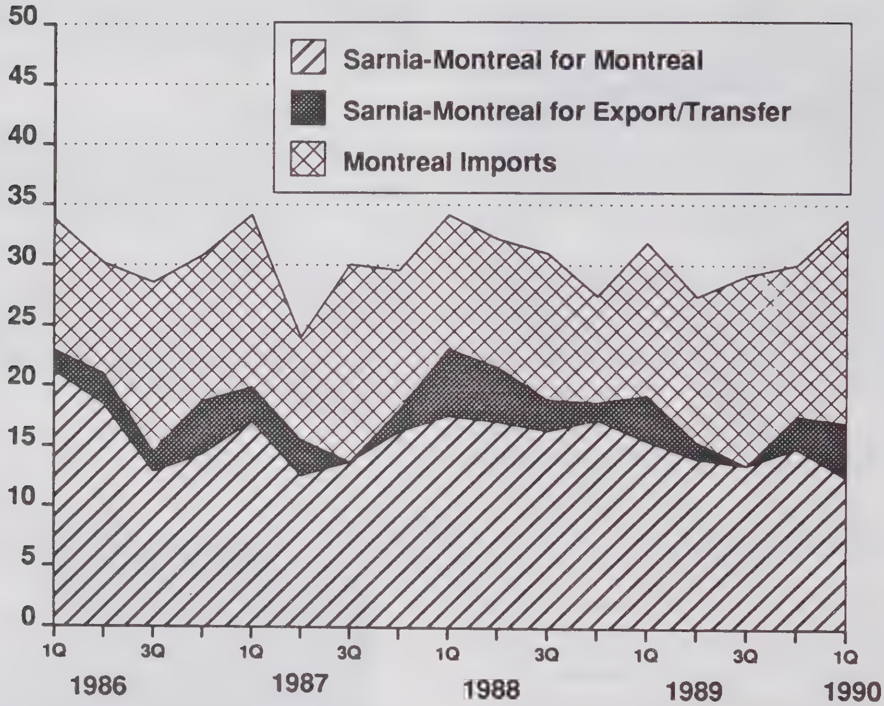


5.3 Pipelines to Montreal

Total deliveries of crude oil and equivalent to Montreal refiners, during the first quarter of 1990, averaged about 29 300 m^3/d, up 1 500 m^3/d from the same quarter a year earlier.

Although total domestic crude deliveries via the Sarnia-Montreal portion of the IPL system averaged 17 000 m^3/d, 2 100 m^3/d less than the year before, only 12 500 m^3/d were for use by Montreal refineries with the remainder (4 500 m^3/d) exported. On the other hand, foreign crudes, imported mainly through the Portland Pipe Line, grew by 4 300 m^3/d to reach 16 800 m^3/d, an increase of 34% over last year.

Figure 5.3
Deliveries to Montreal
000 m^3/d



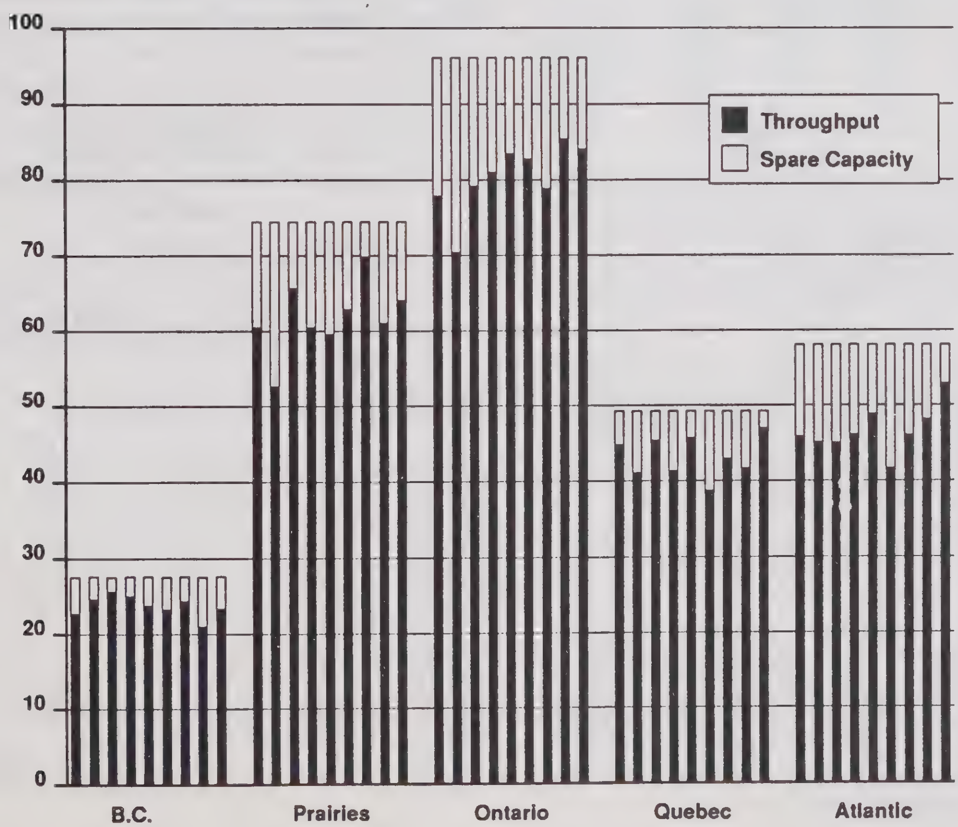
6. Refinery Throughput and Utilization Rates

- *The refinery utilization rate in Canada reached almost 90% during the first quarter with the highest regional rate recorded in Quebec at 95%.*

Refinery throughput will normally diverge from refinery crude oil receipts for two reasons. First, feedstocks other than crude oil are also charged in the refining process. Some of the 'other' feedstocks include gas plant butanes (used mostly by Prairie refineries) and partially processed oil (used mostly by B.C. refineries). During the first quarter, these 'other' receipts averaged 14 000 m^3/d or about 5% of total refinery throughput in Canada. Second, refinery throughput reflects changes in feedstock inventories. An inventory drawdown will cause refinery throughput to exceed receipts - and vice versa in the case of an inventory build.

During the first quarter, total throughput exceeded 271 000 m^3/d, about 10 000 m^3/d higher than during the corresponding period in 1989. With total Canadian refining capacity estimated to be about 306 000 m^3/d, this level of throughput corresponded to an across Canada average refinery utilization rate of about 89%. Such a high rate of utilization has not been observed at the national level since the Seventies. The utilization rate was particularly high in Quebec where it reached 95% . The figure below illustrates refinery throughputs and capacities by region, starting from the first quarter of 1988.

Figure 6.1
Refinery Utilization vs Capacity
(1st Quarter 1988 to 1st Quarter 1990)
000 m^3/d



7. Stocks

- *Closing stocks of crude oil and petroleum products were 14% higher than a year earlier with most of the increase occurring in product stocks*

As illustrated in table 7.1, closing March 1990 crude oil and petroleum product stocks totalled 15.6 million m^3, 14% higher than the same period last year. Petroleum product stocks, representing about 82% of the total, increased by 12%. Stocks of crude oil jumped by nearly 25%.

Table 7.1
Closing Crude and Product Inventories
(End March)
000 m^3

	Crude		Product		Total	
	1989	1990	1989	1990	1989	1990
Canada	2,294	2,866	11,334	12,708	13,628	15,574
Atlantic	676	1,058	1,900	2,053	2,576	3,111
Quebec	783	737	2,222	2,423	3,005	3,160
Ontario	547	657	3,487	3,746	4,034	4,403
Prairies	218	324	2,554	3,214	2,772	3,538
B.C.	70	90	1,171	1,272	1,241	1,362

There has been a steady buildup of crude and product stocks since the beginning of the year. Stocks were built during the first quarter prior to scheduled second-quarter refinery maintenance programs.

Changes in total stock levels were, for the most part, concentrated in the Atlantic and Prairies regions. End of March inventories in the Atlantic region increased by 21% primarily on the strength of a 57% jump in crude oil stocks. Stocks in the Prairies increased by 28% with product inventories up 26%. All other regions increased their respective stock levels from 5% to 10%.

Inventories of "main" petroleum products, as illustrated by table 7.2, accounting for about 70% of total petroleum product stocks, increased by 12% from a year earlier. Stocks in the "other" petroleum products category which includes such products as jet fuel, petrochemicals and asphalt, increased by about 21%.

Table 7.2
Closing Petroleum Product Inventories
(End March)

	000 m^3		Days *	
	1989	1990	1989	1990
All Products	11,334	12,708	51	53
"Main" Products	8,020	8,700	45	45
Motor Gasoline	3,977	4,309	46	45
Heating Oil	1,174	1,047	45	42
Diesel Oil	1,983	2,315	48	48
Heavy Fuel Oil	886	1,029	39	40

* *Ratio of stocks to consumption*

By the end of March, the ratio of stocks to consumption for crude oil and petroleum products, table 7.3, represented about 65 days of forward consumption, up one day from a year earlier. If the Atlantic region is excluded from the calculation because a large portion of Atlantic shipments are directed to the export market and the region is not "pipeline-connected" to domestic supplies, the ratio for the rest of Canada would have been 60 days.

Table 7.3
Ratio of Stocks to Consumption
(End March)
Days

	Crude		Product		Total	
	1989	1990	1989	1990	1989	1990
Canada	13	12	51	53	64	65
Atlantic	30	32	59	60	89	92
Quebec	18	14	46	46	64	60
Ontario	8	7	46	51	54	58
Prairies	6	7	61	65	67	72
B.C.	4	3	47	46	51	49

The stocks above do not include estimates of crude oil held in pipeline tankage. If these stocks were included, the ratio of total stocks to consumption would increase by about 7 days to 72 days of forward consumption.

8. Crude Oil and Product Prices

- *Cold weather pushed prices to peaks not seen since 1986.*
- *Domestic and export crude oil prices continue to track international prices*
- *Pump prices, adjusted for inflation, declined almost 10 cents per litre over the last four years.*

8.1 International Crude Oil Prices

In early January 1990, crude oil prices were at extremely high levels, with spot crude oil trading at peaks not seen since January 1986. West Texas Intermediate (WTI) began 1990 at close to \$24/bbl, but ended the quarter struggling to remain above \$20/bbl. Strong crude prices in January were primarily in response to unusually cold weather conditions in northern hemisphere oil markets (in particular, the U.S.). The situation was further exacerbated by low oil product inventories as several U.S. Gulf Coast refineries were forced to shut-down because of weather-related problems. This resulted in a temporary loss of up to 1.5 MMB/D of refining capacity.

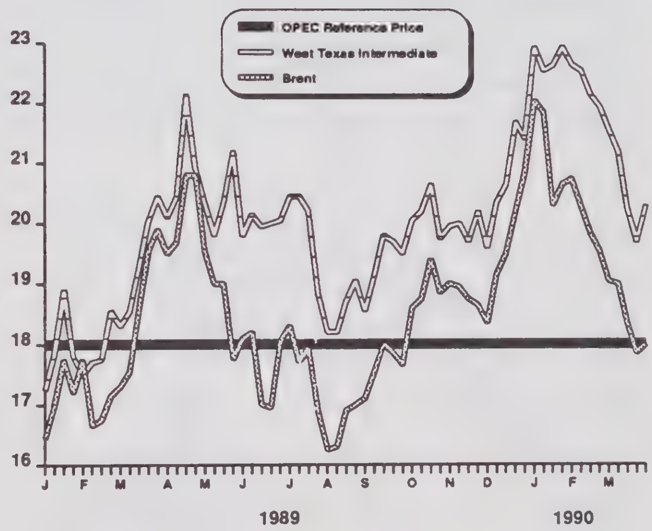
As the first quarter progressed, steadily weakening oil supply/demand fundamentals began to take over world oil markets. These included:

- lower-than-expected world oil demand (excluding CPEs) growth over the first quarter (1.1% growth vs 2.9% in the first quarter, 1989);
- excess OPEC crude oil production (23.6 MMB/D versus a ceiling of 22.1 MMB/D);
- a contraseasonal first quarter stock build; and
- a slowdown in world economic activity, in particular a sluggish U.S. economy.

Of the above-mentioned factors, excess OPEC production was the most damaging to crude oil prices. OPEC crude oil output averaged 23.6 MMB/D, about 1.5 MMB/D above its first quarter ceiling. Kuwait, Saudi Arabia and the United Arab Emirates accounted for most of OPEC's overproduction. However, when OPEC's Market Monitoring Committee met in March to review the world oil market situation, it decided not to take any actions to reduce overproduction. This decision basically reflected the fact that the OPEC basket of crudes was running above its \$18/bbl reference price at the time (first quarter average was \$18.95/bbl).

Figure 8.1 illustrates monthly Brent and WTI prices over the first quarter of 1990. It shows the steady decline in prices over the quarter.

Figure 8.1
Crude Oil Prices
US\$/bbl



8.2 Domestic Crude Oil Prices

During the first quarter of 1990 the posted price of Canadian Par crude oil (the Canadian benchmark crude at 40° API, 0.5%) averaged $25.02/bbl, an increase of $2.23/bbl over the fourth quarter of 1989. The increase can be attributed to a combination of an international oil price increase (about $2.00/bbl), and a weakening of the Canada-U.S. exchange rate.

The differential between Canadian Par and WTI NYMEX prices, on a delivered basis in Chicago, is illustrated in figure 8.2.2. The differential in the first quarter of 1990 averaged US$0.10/bbl in favour of WTI NYMEX, compared to an average of US$0.02/bbl for the fourth quarter, 1989 in favour of Canadian Par. The increase in the differential reflects a seasonal softening of demand for light sweet crude oil in the North American market and the general oversupply of crude oil on international markets.

Figure 8.2.1
Canadian Par Crude vs WTI (NYMEX *) at Chicago
US$/bbl

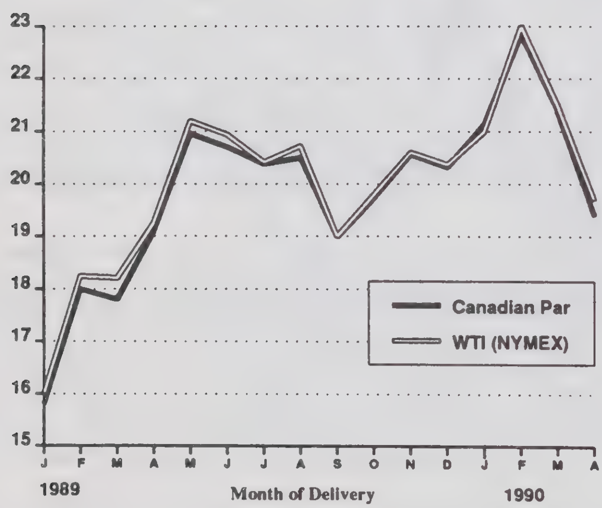


Figure 8.2.2
Canadian Par vs WTI (NYMEX *)
(Differential at Chicago)
US$/bbl

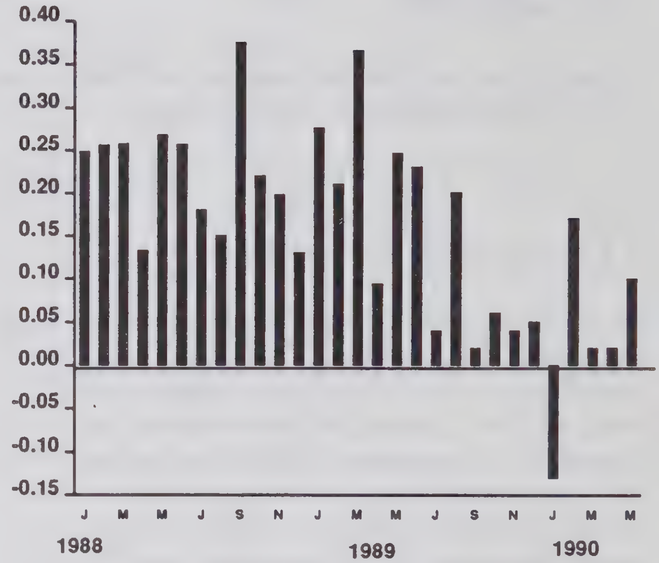
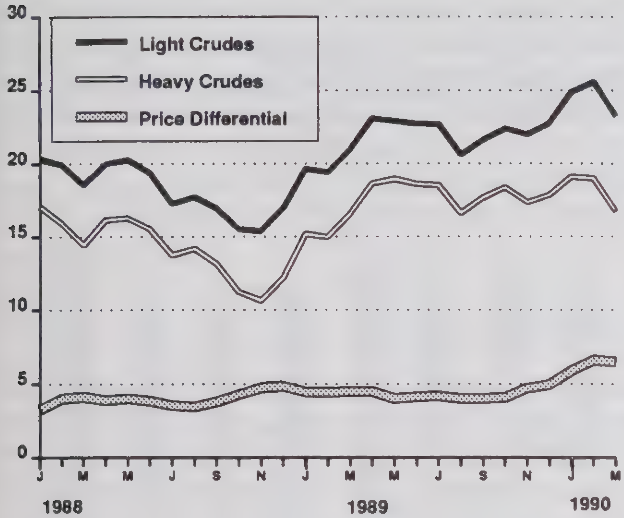


Figure 8.2.3 compares actual prices for Alberta light and heavy crude oil, purchased for use in Canada at the main trunk line injection stations. On average, reported light conventional crude oil quality during the first quarter of 1990 was 37.4° API, 0.41% sulphur and blends of heavy crude were 24.5° API, 2.55% sulphur. The differential between Canadian light and heavy crude oil prices, during the first quarter of 1990 was $6.45/bbl, $1.86/bbl higher than the fourth quarter differential, reflecting both the short-term seasonal change in demand for heavy crude oil and the relative abudance of heavy crude oil supply in the international market.

* *New York Mercantile Exchange*

Figure 8.2.3
Comparison of
Domestic Light and Heavy Crude
(Actual Purchase Price- Alberta)
CAN$/bbl



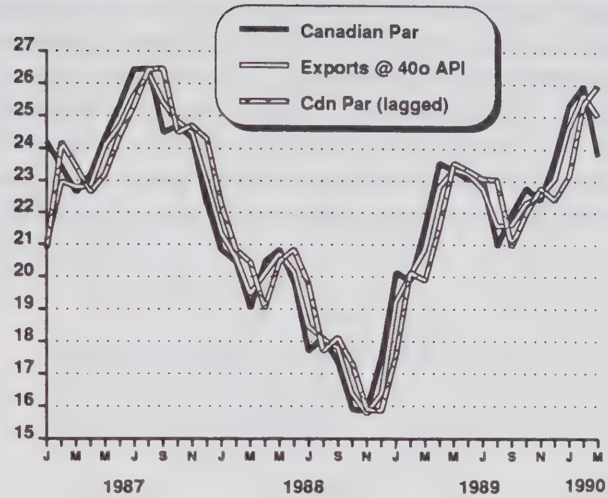
8.3 Export Prices

Figures 8.3.1 and 8.3.2 illustrate the relationship between light crude oil export prices and domestic prices.

Prices of light crude oil exported to the United States via the IPL system were netted back to Edmonton and adjusted to 40° API, on a stream by stream basis. These prices were then compared to Canadian Par crude prices, also at Edmonton.

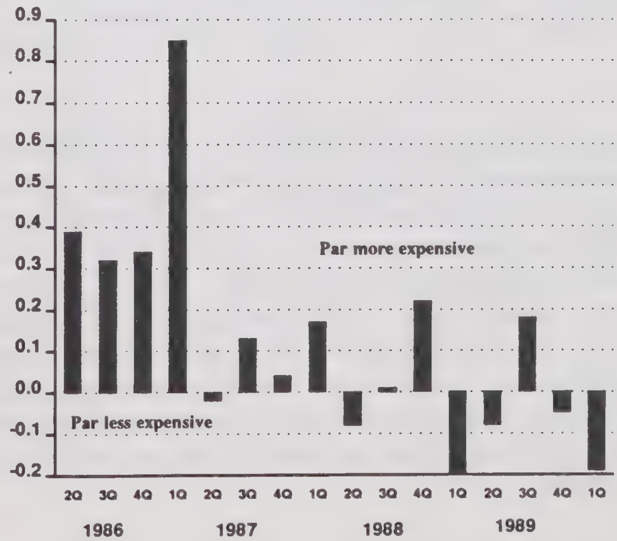
As can be observed in figure 8.3.1, in a period of declining prices, exports would appear to be more expensive than Par crude for the same month; and, in a period of increasing prices, exports would appear to be cheaper. An evaluation on that basis alone would be misleading. Canadian Par crude prices were therefore "lagged" one month to normalize for differing delivery times.

Figure 8.3.1
Light Crude Exports
vs Canadian Par
CAN$/bbl



For comparison purposes, an average of the current month's Par crude and it's lagged price was calculated. Figure 8.3.2 illustrates the differential between this composite average Par crude and the average export price.

Figure 8.3.2
Exports vs Canadian Par
CAN$/bbl (Differential)



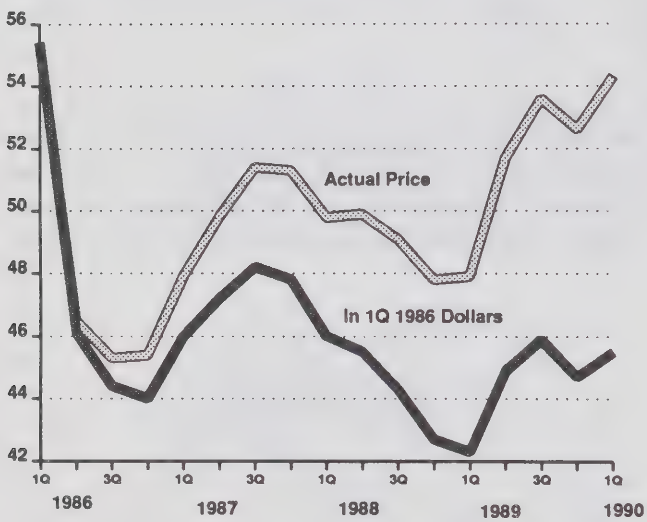
8.4 Petroleum Product Prices

Price Trends

Gasoline and Diesel

In the first quarter of 1990, the average regular unleaded gasoline price, at 54.8 cents per litre, was the highest since the first quarter of 1986. When pump prices are adjusted for inflation, however, the average price, including tax, declined almost 10 cents per litre or 18% over the last 4 years. Also consumer expenditures on motor fuels and lubricants as percentage of total personal expenditures on consumer goods and services declined.

Figure 8.4.1
Regular Unleaded Gasoline Prices
(10 City Average)
cents/litre



During the first quarter of 1990, the average price for self-serve regular unleaded gasoline increased 2.7 cents per litre or 5.2% (March 27, 1990 versus December 26, 1989). Average crude costs increased 1.5 cents per litre (see previous section); federal taxes, 1.1 cents per litre; and provincial taxes, 0.7 cents per litre. The combined crude price and tax increases of 3.3 cents per litre, were not fully recovered at retail. The downstream (refining and marketing) oil sector continues to have a low return on investment compared with other sectors of the economy.

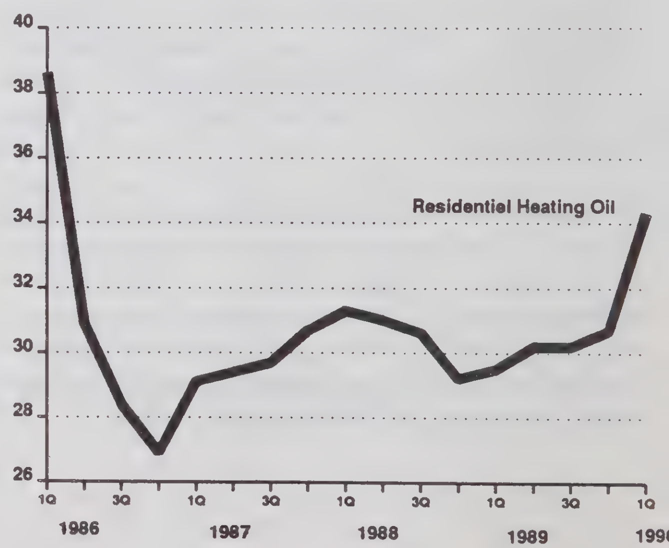
The retail price increased in each of the ten cities surveyed with increases ranging from 1.3 cents per litre in Toronto to 9.1 cents per litre in Regina. Regina enjoyed lower than "normal" prices from the beginning of December 1989 until the middle of January 1990. (See Appendix VI)

Diesel prices continued to increase during the first quarter of 1990 and, like gasoline prices, were the highest in four years. The average increase of 1.9 cents per litre, which brought the average retail price to 51.2 cents per litre, included changes ranging from a decline of 0.2 cents per litre in St. John's, Newfoundland, to a 3.1 cents per litre increase in Saint John, New Brunswick.

Heating Oil

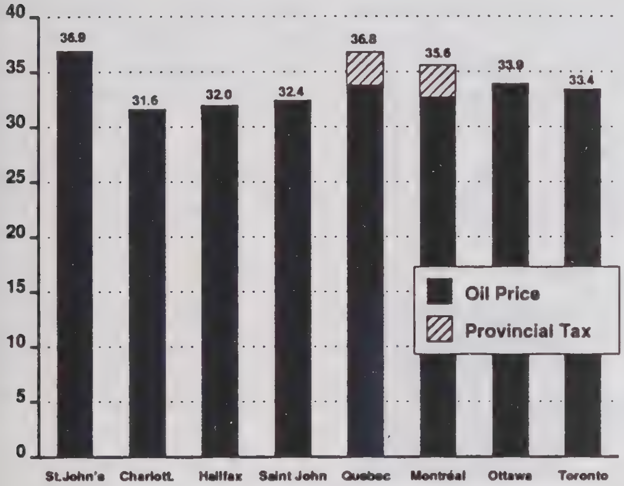
Heating oil prices increased sharply during the first quarter in response to tightening supplies late in 1989. The tight market was the result of unseasonably cold weather in November and December 1989, maintenance at some Quebec refineries, transportation delays resulting from labour problems with Coast Guard employees and supply shortages in eastern United States.

Figure 8.4.2
Residential Heating Oil Prices
(10 City Average)
cents /litre



Heating oil prices in Eastern Canada peaked in February with average prices 3.5 cents per litre, or 11%, above the December 1989 levels. During March prices fell slightly, between 0.3 and 0.5 cents per litre, in centres in Ontario and Quebec, while prices remained unchanged or increased moderately in the Atlantic centres.

Figure 8.4.3
Average Consumer Furnace Oil Prices
(March 1990)
cents /litre



Consumption Taxes on Petroleum Products

The federal sales and excise taxes increased during the first quarter. As a result of the quarterly review process, the sales tax was up about 0.1 cent per litre on gasoline and only 0.02 cent per litre on diesel. The April 1989 federal budget called for a 1 cent per litre excise tax increase on gasoline, effective January 1, 1990. The excise tax on diesel was unchanged. (See Appendix VII)

Ontario's May 1989 budget resulted in a 1 cent per litre gasoline tax increase on January 1, 1990. In Prince Edward Island's March 1990 budget the ad valorem rate was increased to 23% on gasoline and 26% on diesel. While Alberta increased its gasoline and diesel tax 2 cents per litre as a result of their annual budget, they continued to have the lowest provincial gasoline and diesel taxes. Tax adjustments in Newfoundland, Nova Scotia, New Brunswick and British Columbia were the result of regular reviews.

Canada vs United States

During the first quarter of 1990, the average retail price for all grades of motor gasoline increased twice as much in Canada as it did in the United States. The differential in March, 22.7 cents per litre, was 1.7 cents per litre higher than at the end of 1989. The two main factors contributing to the wider differential are increased Canadian taxes and, to a lesser extent, a shift in demand to higher octane gasoline.

Higher taxes in Canada continued to account for the bulk of the differential, about 70% in March 1990. The balance is attributable to higher refining and marketing costs and/or profits in Canada.

Figure 8.4.4
Average Retail Price of Motor Gasoline
(Canada vs United States)
cents /litre

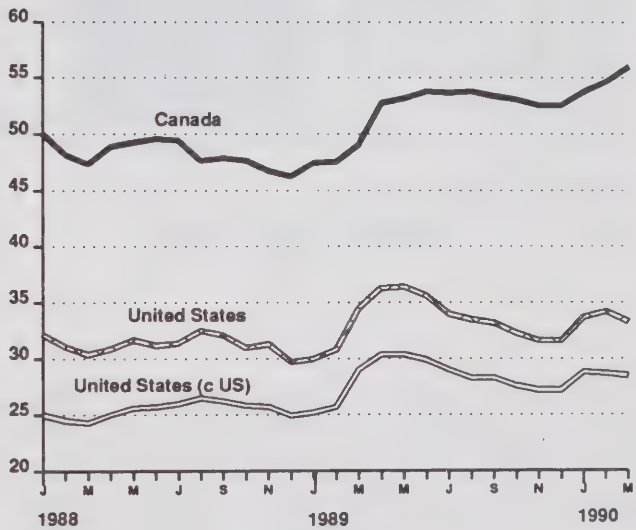
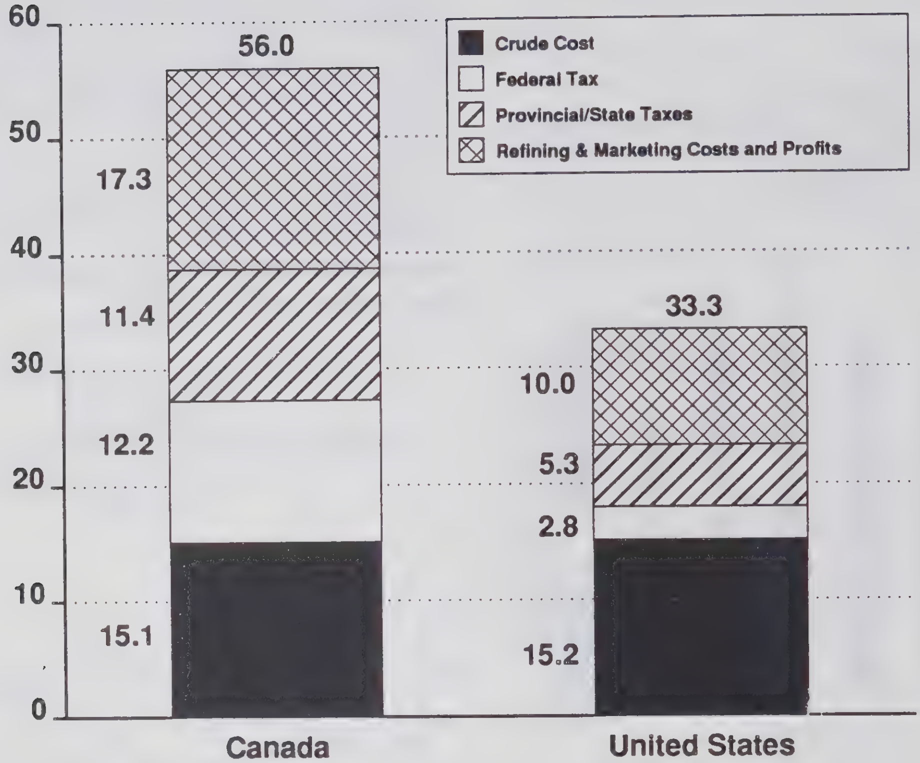


Figure 8.4.5
Breakdown of Average Pump Price
(March 1990)
cents /litre



Exchange Rate = 1.1702

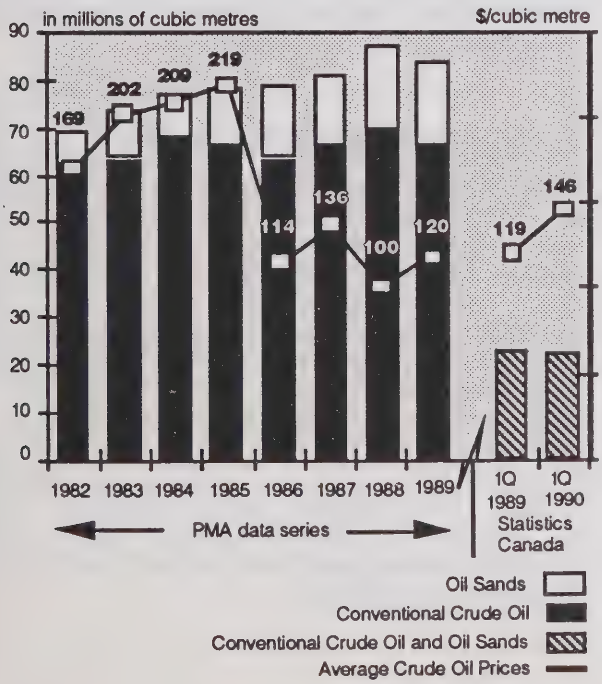
9. Financial Performance of the Canadian Oil and Gas Industry

The following section was prepared by the Petroleum Monitoring Agency (PMA). Further information is available from V. Stanciulescu (613) 995-2100 and F. Laberge 996-8035.

- *Internal cash flow decreased 9% to $1.8 billion in the first quarter of 1990 from $2 billion in the corresponding 1989 period.*
- *Net income after unusual items fell 13% to $500 million in the first quarter of 1990.*
- *Gross capital expenditures increased 5% to $1.6 billion in the first quarter of 1990 with a corresponding rise in the reinvestment rate to 84%, from 73% in the corresponding 1989 period.*
- *Dividend payments in the first quarter of 1990 declined 44% to $225 million from $405 million.*

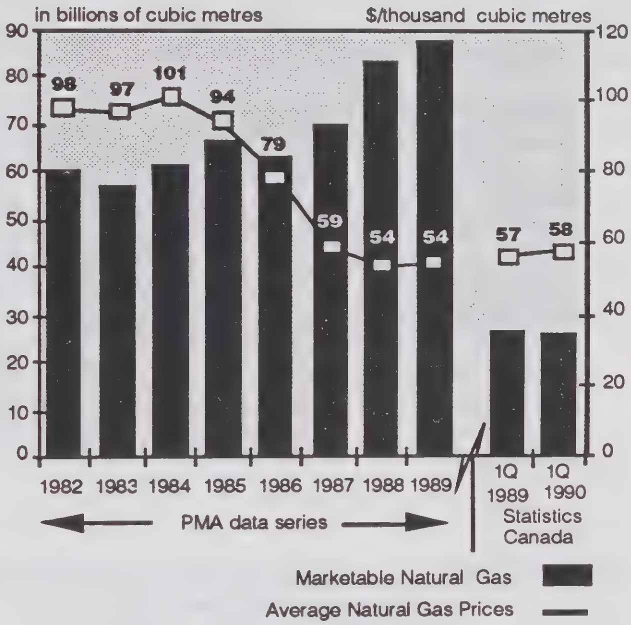
Total sales revenues increased 11% to $10.3 billion in the first quarter of 1990 from $9.3 billion in the corresponding 1989 period. The increase was mainly the result of higher crude oil and NGL prices, which more than compensated for the decline in crude oil production.

Figure 9.1 Crude Oil Volumes and Average Prices: 1982 - 1990



The natural gas market remained relatively unchanged, both in terms of production and prices. Higher sales revenues were realized from refined petroleum products, reflecting the flow through to consumers of increased feedstock costs and federal sales and excise taxes, although sales volumes were marginally lower.

Figure 9.2 Marketable Natural Gas Volumes and Average Prices: 1982 - 1990



Note: The data for figures 9.1 and 9.2 are taken from the PMA's Monitoring Survey results except for the two end bars which are derived from Statistics Canada and EMR Oil and Gas Branch. The two data series are **not** entirely comparable since the PMA data shows prices to the producers, while the other data includes transportation and gathering costs and are, therefore, higher than PMA numbers. The Monitoring Survey covers approximately 90% of the industry, compared with 100% for the other data series.

Internal cash flow declined 9% to $1.8 billion in the first quarter of 1990. The rise in sales revenues was more than offset by higher expenses. 'Other expenses', including operating costs, cost of goods sold (feedstock costs) and royalty payments increased $1 billion (14%) in the first quarter of 1990 over the corresponding 1989 period (Table 9.6). Also, higher interest payments of 17% (or $85 million) and increased current income taxes of 54% (or $160 million) caused the decrease in cash flow.
Most of the increase in current taxes was due to deferral of tax liability from 1989 to 1990 following corporate restructuring. As a result, a large current income tax was reported in the first quarter of 1990, offset by a negative deferred tax.

Net income from all Canadian operations of the industry fell 13% to $515 million in the first quarter of 1990. An extraordinary gain of $45 million in the first quarter of 1989, together with an equity gain of $70 million vs. an equity gain of only $35 million in the first quarter of 1990 contributed to the decline in profits. Before extraordinary items, net income declined 2% to $490 million. In addition, increased interest expenses and higher current income taxes more than offset higher gains on sale of assets, lower E&D charges to current operations and reduced deferred taxes (Table 9.6).

Figure 9.3 Crude Oil Acquisition Costs vs. Petroleum Product Prices: Monthly, 1988 - 1990

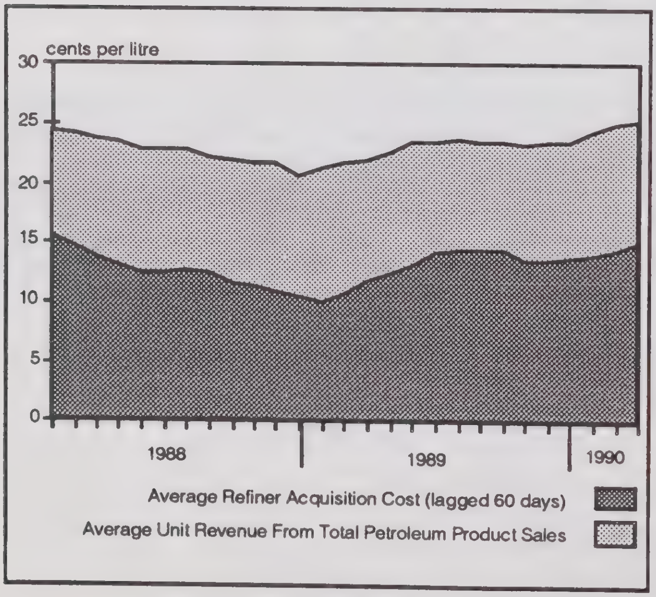


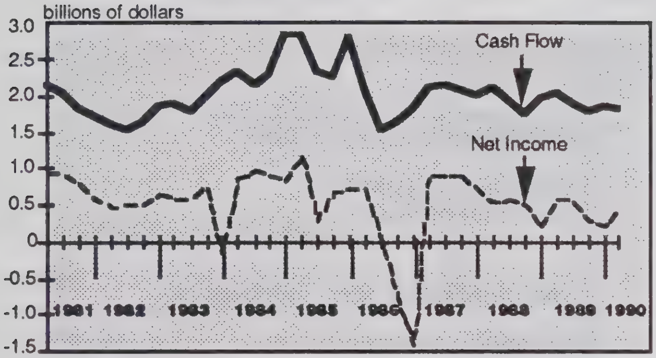
Table 9.1 Overview of Total Industry

	1989	1990	Change	
	---- $ billions ----			(%)
Total Sales Revenue	9.3	10.3	1.0	11
Total Expenses	8.6	9.6	1.0	12
Other Revenues	0.2	0.3	0.1	71
All Current Taxes	0.3	0.5	0.2	54
Deferred Taxes	0.1	-	-0.1	-
Net Income before Extraordinary Items	**0.5**	**0.5**	**-**	**-2**
Extraordinary and Other Items	0.1	-	-0.1	-74
Net Income after Extraordinary Items	**0.6**	**0.5**	**-0.1**	**-13**
Internal Cash Flow	**2.0**	**1.8**	**-0.2**	**-9**

Canadian-controlled companies' cash flow increased 8% ($65 million) to $830 million in the first quarter of 1990 from $770 million in the corresponding 1989 period. Higher sales revenue, up $385 million or 12%, was partly offset by a $290 million increase in 'other expenses', which includes operating and feedstock costs, and higher interest charges, up $30 million or 16%.
Net income declined 18% to $190 million in the first quarter of 1990 due to increased E&D expenses charged to current operations, higher deferred income taxes, and extraordinary gains of $15 million in the first quarter of 1989 against an extraordinary loss of $5 million.

Foreign-controlled companies' cash flow fell 20% ($250 million) to $1 billion in the first quarter of 1990 compared to $1.3 billion in the corresponding 1989 period. A $640 million (11%) gain in total revenues was more than offset by a $650 million rise in 'other expenses'. Also, increased current income taxes and interest expenses of $155 million and $50 million pushed cash flow lower.
Net income for this group fell $35 million (10%). In addition to the factors affecting cash flow, reduced E&D charges to current operations (down $65 million) and deferred taxes ($100 million), and higher gains on sale of assets (up $105 million), kept net income from declining as steeply as cash flow.

Figure 9.4. Net Income and Cash Flow 1981-1990: Quarterly Data



Dividend payments by the petroleum industry decreased 44% to $225 million in the first quarter of 1990 from $405 million in the corresponding 1989 period. Dividends paid by Canadian-controlled companies increased 12% to $100 million, while dividend payments by foreign-controlled companies fell 61% to $125 million. In the first quarter of 1989, Texaco Canada Inc. declared a dividend 'in specie' of one common share of Texaco Canada Petroleum Inc. for each outstanding share of the corporation. This transaction resulted in an artificially high dividend payment reported in 1989. Canadian-controlled companies' payout rate was 53% of net income compared with 38% for foreign-controlled companies in the first quarter of 1990.

Table 9.2 Dividend Payments

	1989	1990	Per Cent of Net Income(a) 1989	1990
	- -$ millions - -		(%)	
Canadian-Controlled	91	102	39	53
Foreign-Controlled	314	123	87	38
Total Industry	405	225	68	44

(a) Percentages are derived by dividing dividend payments by the net income.

Overall gross capital expenditures for the petroleum industry increased 2% ($30 million) to $1.5 billion in the first quarter of 1990. Capital expenditures, net of grants and incentives, rose 5% as incentives dropped 83% to $10 million from $55 million.

Table 9.3 Capital Expenditures and Reinvestment Rates

	1989	1990	Change	
	--- $ billions ---			(%)
Gross Capital Expenditures	1.5	1.6	0.1	2
Less: Incentive Grants	0.1	-	-	-83
Net Capital Expenditures	1.5	1.5	-	5
Reinvestment Rate: Net Capital Expenditures as a Per Cent of Cash Flow	73%	84%		

Exploration and development spending fell 6% to $950 million in the first quarter of 1990, while other capital expenditures increased 17% to $605 million. Gross capital outlays for Canadian-controlled companies rose 14% to $720 million, while those of foreign-controlled companies fell 7% to $830 million (Table 9.5). Capital expenditures, net of incentives, for Canadian-controlled companies increased 20% while those for foreign-controlled companies declined 15%.

The total reinvestment rate increased to 84% in the first quarter of 1990 from 73% in the corresponding 1989 period (Table 9.4). The reinvestment rate for Integrateds and Refiners increased to 72% from 61%, while that of the Oil and Gas Producers group rose to 92% from 81%.

Figure 9.5 Capital Expenditures and Reinvestment Rates: 1981-1990

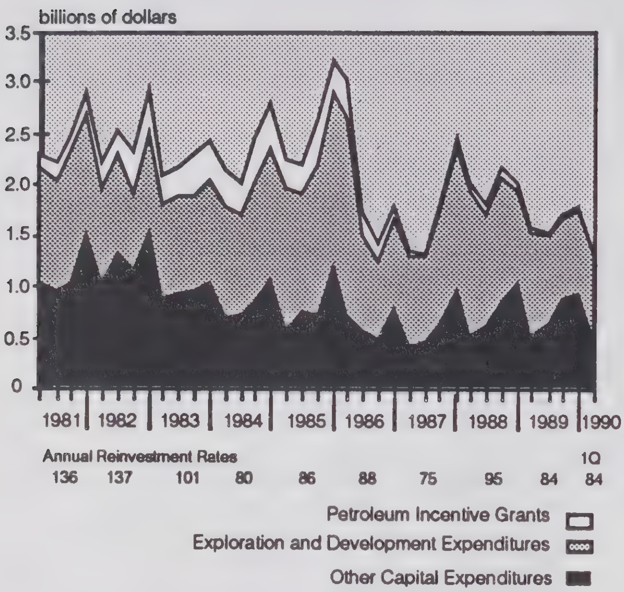


Table 9.4 Total Capital Expenditures (Net Of Incentive Grants) as a Per Cent of Internal Cash Flow
First Quarter

	1989	1990
	-------(%)------	
Integrateds and Refiners	61	72
Canadian-Controlled	79	109
Foreign-Controlled	57	62
Senior Oil and Gas Producers	71	86
Canadian-Controlled	58	65
Foreign-Controlled	82	117
Junior Oil and Gas Producers	104	102
Canadian-Controlled	105	103
Foreign-Controlled	103	99
Oil and Gas Producers	81	92
Canadian-Controlled	77	80
Foreign-Controlled	86	112
Total Industry	**73**	**84**
Canadian-Controlled	78	86
Foreign-Controlled	69	82

Note: This report was prepared on the basis of the quarterly data submitted by individual companies to the PMA via Statistics Canada. In contrast to the bi-annual PMA survey presentation, the report covers the combined results of upstream, downstream and other Canadian operations but excludes the results of Canadian companies' foreign activities. Nonetheless, the information contained in this analysis gives a reliable overview of the industry's financial performance for the first quarter of 1990.

Table 9.5

Capital Expenditures of Petroleum Industry
First Quarter

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1989	1990	Change %	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions			$ millions		
Exploration and Development									
E&D Expensed									
Land & Lease Acquisition and Retention	17	27	59	3	2	-33	14	24	71
Drilling Expenditures	104	91	-13	23	50	117	81	41	-49
Geological and Geophysical	117	106	-9	7	10	43	110	96	-13
Total E&D Expensed	238	224	-6	33	62	88	205	161	-21
E&D Capitalized									
Land & Lease Acquisition and Retention	150	150	-	70	78	11	80	71	-11
Drilling Expenditures	527	500	-5	243	287	18	284	213	-25
Geological and Geophysical	92	75	-18	62	51	-18	30	24	-20
Total E&D Capitalized	769	725	-6	375	416	11	394	308	-22
Total Exploration and Development	**1007**	**949**	**-6**	**408**	**478**	**17**	**599**	**469**	**-22**
Other Capitalized Expenditures									
Mining	35	20	-43	10	11	10	24	9	-63
New Const., Build., Mach., and Equip.	404	511	26	188	212	13	216	299	38
Used Build., Mach., Equip., & Land	24	33	38	12	6	-50	12	27	125
Other Capital Expenditures	52	39	-25	12	12	-10	40	26	-35
Total Other Capital Expenditures	515	603	17	222	241	9	292	361	24
Total Capital Expenditures	**1522**	**1552**	**2**	**630**	**719**	**14**	**891**	**830**	**-7**
Capital Grants	53	9	-83	35	5	-86	18	4	-78
Net Capital Expenditures	**1469**	**1543**	**5**	**595**	**714**	**20**	**873**	**826**	**-5**

Table 9.6

Income Statement
First Quarter

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1989	1990	Change %	1989	1990	Change %	1989	1990	Char
	$ millions			$ millions			$ millions		
Sales Revenues	**9254**	**10278**	**11**	**3149**	**3533**	**12**	**6105**	**6745**	
Other Revenues									
Interest from Canadian Sources	110	102	-8	42	41	-1	69	61	
Dividends from Canadian Corporations	16	21	26	7	17	-	9	4	
Foreign Dividends and Interest Revenues	3	3	-3	2	-	-	1	3	
Gains on Sale of Assets	17	127	-	9	14	54	9	113	
Total Revenues	**9401**	**10530**	**12**	**3208**	**3605**	**12**	**6193**	**6925**	
Expenses									
E & D Expensed	265	228	-14	35	63	78	229	165	
D, D & A Charges	1251	1282	3	525	555	6	726	727	
Other Expenses	6572	7511	14	2150	2440	14	4422	5071	
Interest Expenses	496	578	17	203	235	16	293	343	
Total Operating Expenses	**8583**	**9599**	**12**	**2913**	**3293**	**13**	**5669**	**6306**	
Other Transactions									
Gains on Translation of Currency	40	26	-36	11	-1	-	29	26	
Write-offs and Valuation Adjustments	-6	-23	-	1	-3	-	-6	-20	
Income before Income Taxes	**854**	**934**	**9**	**307**	**308**	**1**	**547**	**626**	
Income Taxes									
Current	295	455	54	78	81	4	216	373	
Deferred (tax allocation method)	62	-8	-	42	70	67	20	-78	
Net Income after Income taxes	**497**	**487**	**-2**	**187**	**157**	**-16**	**311**	**330**	
Other Income									
Equity Income	52	35	-33	31	42	35	21	-7	
Extraordinary Items	45	-7	-	17	-7	-	28	-	
Net Income after Extraordinary Items	**594**	**515**	**-13**	**234**	**192**	**-18**	**360**	**323**	**-**
Cash Flow	**2022**	**1838**	**-9**	**768**	**832**	**8**	**1254**	**1005**	**-**

	Integrateds and Refiners			Oil and Gas Producers		
	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions		
Sales Revenues	**5698**	**6245**	**10**	**3556**	**4033**	**13**
Other Revenues						
Interest from Canadian Sources	61	48	-22	49	54	11
Dividends from Canadian Corporations	3	3	-17	13	18	36
Foreign Dividends and Interest Revenues	-	-	-	3	3	-2
Gains on Sale of Assets	10	120	-	7	7	-11
Total Revenues	**5772**	**6416**	**11**	**3629**	**4114**	**13**
Expenses						
E & D Expensed	69	59	-15	196	170	-13
D, D & A Charges	466	513	10	785	769	-2
Other Expenses	4507	5145	14	2065	2365	15
Interest Expenses	177	215	22	319	363	14
Total Operating Expenses	**5218**	**5932**	**13**	**3364**	**3667**	**9**
Other Transactions						
Gains on Translation of Currency	11	-	-	30	26	-14
Write-offs and Valuation Adjustments	3	-13	-	-9	-10	-
Income before Income Taxes	**568**	**471**	**-17**	**285**	**463**	**63**
Income Taxes						
Current	201	160	-20	93	294	-
Deferred (tax allocation method)	38	41	7	24	-49	-
Net Income after Income taxes	**329**	**270**	**-18**	**168**	**218**	**30**
Other Income						
Equity Income	22	12	-43	31	23	-26
Extraordinary Items	1	-	-	44	-7	-
Net Income after Extraordinary Items	**351**	**282**	**-20**	**243**	**234**	**-4**
Cash Flow	**877**	**762**	**-13**	**1145**	**1075**	**-6**

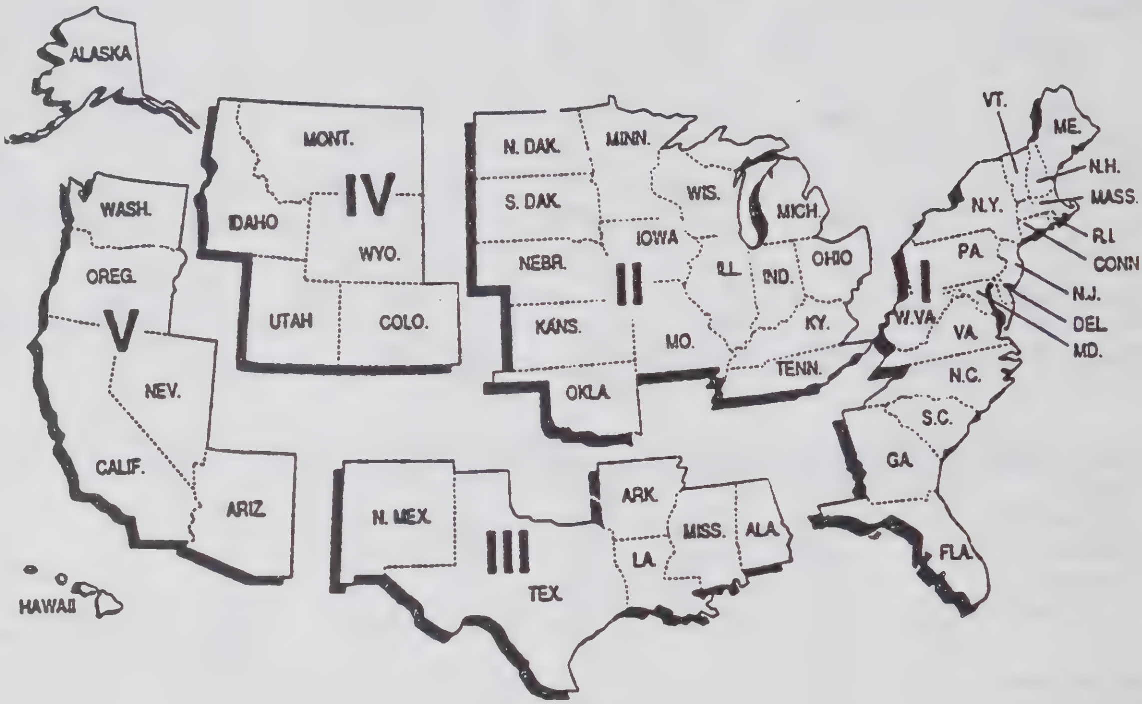
Appendix I

Production of Canadian Crude Oil and Equivalent

	Period	1Q89	2Q89	3Q89	4Q89	1989	1Q90	1Q90/ 1Q89	1Q90/ 4Q89
		(000 m^3/d)						(% Change)	
A.	**Light and Equivalent**								
	Alberta	130	123	123	122	124	121	*8*	*-1*
	B.C	5	5	5	6	5	6	*20*	-
	Saskatchewan	11	10	11	10	11	10	*-9*	-
	Manitoba	2	2	2	2	2	2	-	-
	Other	5	5	5	5	5	5	-	-
	Total	**153**	**145**	**146**	**145**	**147**	**144**	***-6***	***-1***
	Synthetic								
	Suncor	9	9	10	8	9	9	-	*-13*
	Syncrude	21	28	19	24	24	17	*-19*	*29*
	Total	**30**	**37**	**29**	**32**	**33**	**26**	**-13**	**19**
	Pentanes Plus	**8**	**7**	**8**	**9**	**8**	**6**	***-25***	***33***
	Total Light & Equiv.	**191**	**189**	**183**	**186**	**188**	**176**	***-8***	***-5***
B.	**Heavy Crude**								
	Alberta								
	Conventional	24	24	25	27	25	27	*12*	-
	Bitumen	20	21	21	19	20	21	*5*	*11*
	Diluent*	10	9	9	9	9	10	-	*11*
	Total	**54**	**54**	**55**	**55**	**54**	**58**	*7*	*6*
	Saskatchewan								
	Crude	21	20	21	22	21	21	-	*-5*
	Diluent	3	2	2	3	3	3	-	-
	Total	**24**	**22**	**23**	**25**	**24**	**24**	-	*-4*
	Total	**78**	**76**	**78**	**80**	**78**	**82**	*5*	*3*
C.	**Production**	**269**	**265**	**261**	**266**	**266**	**258**	*4*	*-3*
D.	**Shut-In**								
	Light	4	8	7	3	5	5	*25*	*67*
	Heavy	4	4	3	1	3	2	*-50*	*100*
	Total	**8**	**12**	**10**	**4**	**8**	**7**	***-12***	*75*
E.	**Total Capacity**	**277**	**277**	**271**	**270**	**274**	**265**	4	2
	** Includes Recycled Diluent*	*1*	*1*	*1*	*1*	*1*	*1*	-	-

Appendix II

U.S. Petroleum Administration for Defense (PAD) Districts



Appendix III
Supply And Disposition of Canadian Crude Oil and Equivalent

	Period	1Q89	2Q89	3Q89	4Q89	1989	1Q90	1Q90/ 1Q89	1Q90/ 4Q89
		(000 m^3/d)						(% Change)	
A.	**Light and Equivalent**								
	Supply								
	Production	191	189	183	186	188	176	*-8*	*-5*
	Pipeline Inv. Draw/(Build)	3	3	6	3	3	7		
	Net Supply	194	192	189	189	191	183	*-6*	*-3*
	Domestic Demand								
	Atlantic	-	-	-	-	-	-	-	-
	Quebec	10	9	8	10	9	7	*-30*	*-13*
	Ontario	68	65	60	67	65	68	-	*2*
	Prairies	49	52	59	52	53	54	*10*	*4*
	B.C.	17	18	19	16	17	18	*6*	*13*
	Total	**144**	**144**	**146**	**145**	**144**	**147**	***2***	***1***
	Exports	**50**	**48**	**43**	**44**	**47**	**36**	***-28***	***-18***
	Total Demand	**194**	**192**	**189**	**189**	**191**	**183**	***-5***	***-3***
B.	**Heavy Crude***								
	Supply								
	Production	78	76	78	80	78	82	*5*	*3*
	Pipeline Inv. Draw/(Build)	-	4	-3	-4	-	-		
	Net Supply	78	80	75	76	78	82	*5*	*8*
	Domestic Demand								
	Atlantic	-	-	-	-	-	-	-	-
	Quebec	5	4	3	4	4	5	-	*25*
	Ontario	10	10	9	9	10	9	*-10*	-
	Prairies	7	9	9	5	7	7	-	*40*
	B.C.	-	1	1	1	1	-	-	*100*
	Total	22	24	22	19	22	21	*-5*	*11*
	Exports	**56**	**56**	**53**	**57**	**56**	**61**	***9***	***7***
	Total Demand	**78**	**80**	**75**	**76**	**78**	**82**	***-5***	***8***

** Includes diluent*

Appendix IV
Pipeline Deliveries

		1Q89	2Q89	3Q89	4Q89	1989	1Q90	1Q90/ 1Q89	1Q90/ 4Q89
		(000 m³/d)						(% Change)	
A.	**Trans-Mountain Pipe Line (TMPL)**								
	Domestic Deliveries								
	Light Crude Oil	13.4	15.1	14.3	12.9	13.9	13.5	*0.7*	*4.7*
	Heavy Crude Oil	0.8	0.6	0.5	0.5	0. 6	0.2	*-75.0*	*-60.0*
	Semi Refined Products	5.6	4.7	5.2	6.2	5.4	5.1	*-8.9*	*-17.7*
	Refined Products	2.5	2.7	2.7	3.0	2.7	2.7	*8.0*	*-10.0*
	Total	**22.3**	**23.1**	**22.7**	**22.6**	**22.7**	**21.5**	***-3.6***	***-4.9***
	Foreign Deliveries								
	Tankers	3.1	2.6	1.2	3.8	2.7	4.4	*41.9*	*15.8*
	Puget Sound Area	2.9	3.6	1.9	2.4	2.7	0.7	*-75.9*	*-70.8*
	Total	**6.0**	**6.2**	**3.1**	**6.2**	**5.4**	**5.1**	***-15.0***	***-17.7***
	Total TMPL	**28.3**	**29.3**	**25.8**	**28.8**	**28.1**	**26.6**	***-6.0***	***-7.6***
B.	**Interprovincial Pipe Line (IPL)**								
	Domestic Deliveries								
	Light Crude Oil	46.1	47.7	40.9	43.5	44.6	41.0	*-11.1*	*-5.7*
	Heavy Crude Oil	72.4	69.9	66.0	67.5	69.0	72.0	*-0.6*	*6.7*
	Other (1)	26.3	26.7	25.0	27.6	26.4	27.6	*4.9*	*0.0*
	Total	**144.8**	**144.3**	**131.9**	**138.6**	**139.9**	**140.6**	***-2.9***	***1.4***
	Foreign Deliveries (2)								
	Light Crude Oil	45.7	42.2	41.2	38.9	42.0	33.4	*-26.9*	*-14.1*
	Heavy Crude Oil	48.8	48.1	50.1	51.4	49.6	52.3	*7.2*	*1.8*
	Total	**94.5**	**90.3**	**91.3**	**90.3**	**91.6**	**85.7**	***-9.3***	***-5.1***
	Total IPL	**239.3**	**234.6**	**223.2**	**228.9**	**231.5**	**226.3**	***-5.4***	***-1.1***
C.	**Pipelines to Montreal**								
	IPL Deliveries								
	To Montreal Refineries	15.3	14.0	13.5	15.1	14.5	12.5	*-18.3*	*-17.2*
	For Export/Transfer	3.8	1.5	0.0	2.5	2.0	4.5	*18.4*	*80.0*
	Total IPL	**19.1**	**15.5**	**13.5**	**17.6**	**16.4**	**17.0**	***-11.0***	***-3.4***
	Portland-Montreal								
	Montreal Imports (3)	12.5	11.9	15.7	12.5	13.2	16.8	*34.4*	*34.4*
	Total Mtl Receipts	**27.8**	**25.9**	**29.2**	**27.6**	**27.6**	**29.3**	**5.4**	**6.2**

Note (1): includes petroleum products and NGL's.
(2): includes US domestic crudes delivered to the US.
(3): includes cargoes imported directly into Montreal

Appendix V
Refinery Receipts

		1Q89	2Q89	3Q89	4Q89	1989	1Q90	1Q90/ 1Q89	1Q90/ 1Q89
		(000 m^3/d)						(% change)	
A.	**Domestic Feedstock Receipts**								
	Light & Equivalent								
	Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	*n/a*	*n/a*
	Quebec	9.6	9.0	8.0	10.4	9.3	7.1	*-26.0*	*-31.7*
	Ontario	68.3	65.5	57.2	67.3	64.6	67.5	*-1.2*	*0.3*
	Prairies	49.0	52.3	57.7	51.8	52.7	53.7	*9.6*	*3.7*
	B.C.	17.1	17.6	18.1	16.3	17.3	17.6	*2.9*	*8.0*
	Canada	**144.0**	**144.4**	**141.0**	**145.8**	**143.8**	**145.9**	***1.3***	***0.1***
	Heavy								
	Atlantic	0.0	0.0	0.0	0.1	0.0	0.0	*n/a*	*-100.0*
	Quebec	4.9	4.2	4.4	3.7	4.3	5.2	*6.1*	*40.5*
	Ontario	9.9	10.4	9.1	9.4	9.7	8.8	*-11.1*	*-6.4*
	Prairies	6.6	9.1	8.5	4.9	7.3	7.4	*12.1*	*51.0*
	B.C.	0.5	0.5	0.5	0.8	0.6	0.2	*-60.0*	*-75.0*
	Canada	**21.9**	**24.2**	**22.5**	**18.9**	**21.9**	**21.6**	***-1.4***	***14.3***
	Other								
	Atlantic	1.5	0.8	0.2	0.5	0.8	0.8	*-46.7*	*60.0*
	Quebec	1.4	0.8	1.5	1.1	1.2	1.4	*0.0*	*27.3*
	Ontario	4.0	4.0	4.3	4.8	4.3	3.3	*-17.5*	*-31.3*
	Prairies	3.5	2.7	3.4	4.0	3.4	3.4	*-2.9*	*-15.0*
	B.C.	6.5	5.2	5.7	5.9	5.9	5.3	*-18.5*	*-10.2*
	Canada	**16.9**	**13.5**	**15.1**	**16.3**	**15.5**	**14.2**	***-16.0***	***-12.9***
	Total Domestic								
	Atlantic	1.5	0.8	0.2	0.6	0.8	0.8	*-46.7*	*33.3*
	Quebec	15.9	14.0	13.9	15.2	14.8	13.7	*-13.8*	*-9.9*
	Ontario	82.2	79.9	70.6	81.5	78.6	79.6	*-3.2*	*-2.3*
	Prairies	59.1	64.1	69.6	60.7	63.4	64.5	*9.1*	*6.3*
	B.C.	24.1	23.3	24.3	23.0	23.7	23.1	*-4.1*	*0.4*
	Canada	**182.8**	**182.1**	**178.6**	**181.0**	**181.1**	**181.7**	***0.6***	***0.4***
B.	**Crude Oil Imports**								
	Atlantic	46.0	45.7	45.7	47.6	46.3	50.7	*10.2*	*6.5*
	Quebec	28.0	26.0	26.6	25.5	26.5	35.2	*25.7*	*38.0*
	Ontario	1.7	4.2	8.0	2.9	4.2	5.1	*200.0*	*75.9*
	Prairies	0	0	0	0	0	0	*n/a*	*n/a*
	B.C.	0	0	0	0	0	0	*n/a*	*n/a*
	Canada	**75.7**	**75.9**	**80.3**	**76.0**	**77.0**	**91.0**	***20.2***	***19.7***
C.	**Total Receipts**								
	Atlantic	47.5	46.5	45.9	48.2	47.0	51.5	*8.4*	*6.8*
	Quebec	43.9	40.0	40.5	40.7	41.3	48.9	*11.4*	*20.1*
	Ontario	83.9	84.1	78.6	84.4	82.8	84.7	*1.0*	*0.4*
	Prairies	59.1	64.1	69.6	60.7	63.4	64.5	*9.1*	*6.3*
	B.C.	24.1	23.3	24.3	23.0	23.7	23.1	*-4.1*	*0.4*
	Canada	**258.5**	**258.0**	**258.9**	**257.0**	**258.1**	**272.7**	***5.5***	***6.1***

Appendix VI

Average Regular Unleaded Gasoline Prices

(Self-Serve)

1989-1990

	1989 March 28	1989 June 27	1989 Sept. 26	1989 Dec. 26	1990 March 27	% Change 12 mo.
	cents per litre					
St. John's(NFLD)	52.2	56.3	56.7	56.8	58.3	*11.7*
Charlottetown	49.6	51.5	54.1	53.8	56.2	*13.3*
Halifax *	48.8	52.4	52.4	52.4	53.8	*10.2*
Saint John(N.B.)*	50.2	53.3	53.9	51.9	55.2	*10.0*
Montreal	55.0	58.1	58.1	58.1	60.8	*10.5*
Toronto	48.5	50.1	51.3	47.2	48.5	-
Winnipeg	43.9	50.9	51.4	50.7	53.9	*22.8*
Regina	43.3	53.9	53.8	45.8	54.9	*26.8*
Calgary	41.4	48.2	48.1	48.1	51.9	*25.4*
Vancouver	49.5	53.6	54.1	54.9	59.9	*21.0*
Canadian Average	**49.5**	**53.1**	**53.6**	**52.1**	**54.8**	***10.7***
Consumption taxes included:						
Federal	9.8	11.1	11.0	11.0	12.1	*23.5*
Provincial	9.8	10.4	10.5	10.6	11.3	*15.3*

* *Full-serve*

Appendix VII

Consumption Taxes on Petroleum Products

(March 23, 1990)

	Ad valorem Mogas	Ad valorem Diesel	Gasoline Reg L	Gasoline Reg UL	Gasoline Prem UL	Diesel
	(%)		(cents per litre)			
Federal Taxes						
Sales			3.55*	3.55*	3.65*	2.71*
Excise			9.5*	8.5*	8.5*	4.0
Provincial Taxes						
Newfoundland (a)	*23(b)**	*27*	12.5*	11.0*	11.0*	12.3*
Prince Edward Island	*23**	*26**	10.5*	10.5*	10.5*	10.6*
Nova Scotia	*20*	*21*	9.3*	9.3*	9.3*	9.4*
New Brunswick	*24.5(c)*	*31.5*	12.1*	3.0*	10.8*	11.1
Quebec (d)			14.4	14.4	14.4	12.45
Ontario			14.3	11.3*	11.3*	10.9
Manitoba			10.8*	9.0*	9.0*	9.9
Saskatchewan			12.0	10.0	10.0	10.0
Alberta			7.0*	7.0*	7.0*	7.0*
British Columbia (c)	*22.5 (f)*		11.04*	9.04*	9.04*	9.48*
Yukon			4.2	4.2	4.2	5.2
Northwest Territorie	*17*	*(g)*	8.5	8.5	8.5	7.2

(a) *The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay in Labrador.*

(b) *This applies to unleaded gasoline. The tax on leaded gasoline is l.5 cents per litre higher than the unleaded tax.*

(c) *This applies to all gasolines. There is also a 2.2 cent per litre surcharge on regular leaded gasoline.*

(d) *Reduced by varying amounts in certain remote areas and within 20 kilometers of the provincial and U.S. borders.*

(e) *Additional transit tax of 3.0 cents per litre in Vancouver.*

(f) *This applies to unleaded gasoline. Taxes on leaded gasoline and diesel fuel 2.0 and 0.44 cents per litre higher, respectively, than the unleaded tax.*

(g) *85% of gasoline tax.*

** Changed since last quarter.*

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Consumption	Petroleum product consumption based on net sales of products; it excludes oil consumption by the refineries.
Conventional area	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
NGLs	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Shut-in	The unused productive capacity of currently producing oil and gas wells.
Synthetic crude oil	Crude oil produced by treatment in oil upgrading facilities designed to reduce the viscosity and sulphur content.

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Publications

The Canadian Oil Market

Vol. VI, No. 2, Summer 1990

Energy, Mines and Resources Canada
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THE CANADIAN OIL MARKET

Vol. VI, No. 2, Summer 1990

Canadian Oil Markets and Emergency Planning Division
Energy Sector
Energy, Mines and Resources Canada

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The Canadian Oil Market

Overview

Over the first six months of 1990, domestic oil supply and demand continued to decline. Consumption of refined petroleum products (seasonally adjusted), consistent with a general slowdown in economic activity, fell by 1%, compared with a year earlier.

A hoped for upturn in western Canada drilling activity did not materialize. Field activity during the first six months of the year continued to be affected by unstable oil prices, a strong Canadian dollar, high interest rates, high provincial royalty rates and reduced cash flow. Low activity also continued to exacerbate the decline in conventional oil productive capacity.

Against a backdrop of declining productive capacity in the conventional sector, total domestic crude oil and equivalent production during the first half recorded a 4% drop. This drop may have also reflected the decline in domestic product demand compounded by a reduction in crude inventory build as a result of extended spring refinery turnarounds. Although conventional light crude oil production declined, heavy crude oil and bitumen production recorded a small gain.

While exports of domestic crude oil during the first half of the year fell by 4%, imports of crude oil increased by 8%. Sixty percent of Canada's import requirements were supplied by non OPEC sources; in particular, from the North Sea. OPEC sources delivered the remainder to Atlantic region refiners.

Saudi Arabia remained the largest OPEC supplier of imported crude followed closely by Nigeria and Venezuela. Over the first half, deliveries from Iraq accounted for about 3% of total imports while no crude oil deliveries from Kuwait were reported.

According to the Petroleum Monitoring Agency, the Canadian oil and gas industry total sales revenues increased by 7% with most of this increase attributable to higher sales revenues for refined products. Internal cash flow declined by 21% as higher sales revenues were more than offset by increased expenses. Net income for Canadian operations fell by 39%.

1. Refined Product Consumption

- *Seasonally adjusted sales of products in the second quarter moved marginally downward continuing a trend that began early in 1989.*

- *Demand is likely to fall in the second half of 1990 as a result of the crisis in the Middle East.*

- *Lower sales were recorded in most products with the notable exception of fuel oil.*

1.1 Seasonally Adjusted Demand

According to preliminary data from Statistics Canada, consumption of total refined products averaged 236 000 m^3/d, on a seasonally adjusted basis, for the second quarter of 1990, down slightly (1 000 m^3/d), from the previous quarter. The decline in sales of refined products is consistent with the general slowdown in economic activity and price increases, and is in line with the slight downward trend that has emerged since the first quarter of 1989.

The decline in demand is expected to continue into the second half of the year because of higher crude oil and product prices arising from the crisis in the Persian Gulf.

Figure 1.1 illustrates the trend in seasonally adjusted sales over the period 1986 to the first half of 1990.

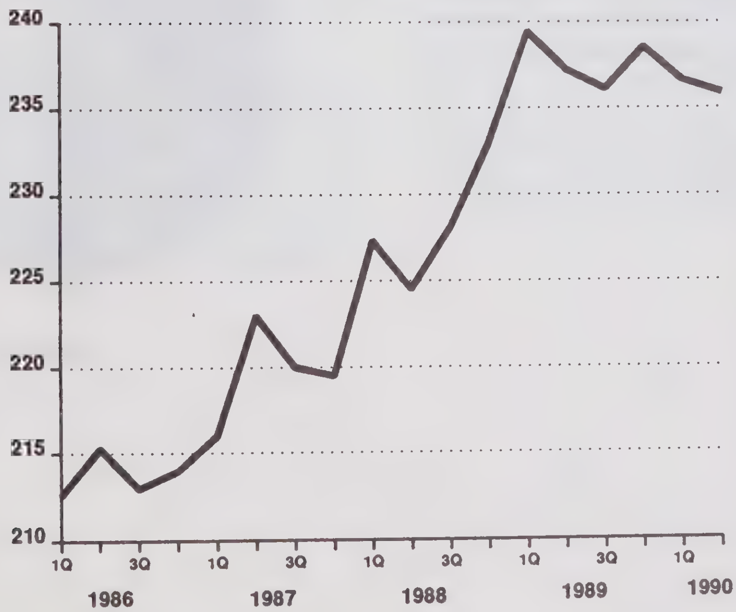
1.2 Petroleum Products

Motor gasoline sales in the second quarter, which accounted for about 40% of total product demand, fell by almost 2% to 94 000 m^3/d from the first quarter of 1990. The decline in demand was attributed, in part, to lower economic activity during the second quarter.

Requirements for diesel oil were also lower at 45 000 m^3/d, down almost 7% from the first quarter and 5% from the annual level in 1989.

Demand rose for light fuel by 12% to 22 000 m^3/d, reflecting a colder than average second quarter.

Figure 1.1
Total Refined Product Consumption
(Seasonally Adjusted)
000 m^3/d



Consumption of heavy fuel oil during the second quarter rose by 3% over the first quarter and nearly 6% over the yearly average for 1989. The increase in demand is primarily attributed to utilities in eastern Canada using residual fuel in the production of electricity to offset a shortfall in hydro generation.

1.3 Regional Demand

Actual consumption of refined petroleum products in Canada for the second quarter of 1990 (before seasonal adjustment) amounted to 225 000 m^3/d, down 1.5%, or 4 000 m^3/d from the same period in 1989. Transportation fuels led the decline in sales with motor gasoline and diesel oil falling by 1.6% and 7.3% to 94 000 m^3/d and 46 000 m^3/d respectively. Use of other products i.e. petrochemical feedstocks, jet fuels, lubes, asphalt and coke, also fell by 7%. Partly offsetting these declines were increases in demand for heating oil up 7% to 14 000 m^3/d and heavy fuel oil up 17% to 26 000 m^3/d. Increased requirements by electrical utilities in Ontario, Quebec and the Atlantic region accounted for the upward trend in sales of heavy fuel oil. The increase in heavy fuel demand was particulary dramatic in Ontario where consumption rose 65%.

The disposition of total product sales by region in the second quarter is displayed in figure 1.3.

Declines in sales of refined products were recorded for Quebec (4.6%), the Prairies (6.4%) and British Columbia (3.2%), while gains in consumption were made in the Atlantic (4.2%) and Ontario (1.7%).

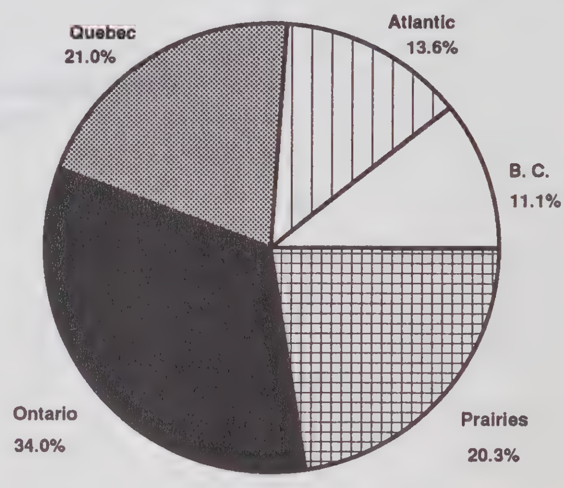
In the Atlantic region, heating oil and heavy fuel oil sales rose by 14.9% and 8.9% respectively over the second quarter sales of 1989.

In Quebec, with the exception of an 18.4% increase in heavy fuel oil, all other products recorded declines in sales. Demand for heating oil and diesel oil fell by 2.4% and 12% respectively. Other products' sales plunged 21%. This reflected lower demand for coke in the manufacturing sector coupled with reduced sales in asphalt and lubes.

Ontario, the largest regional consumer of petroleum products, accounting for about one third of product sales, saw in addition to the substantial heavy fuel oil increase, a 6% rise in sales of heating oil.

The Prairies and British Columbia recorded falling sales in motor gasoline of about 3% and 1%, and in diesel fuel of 11% and 5%.

Figure 1.3
Disposition of Total Products
Regional % Share



225 000 m^3/d

2. Drilling and Exploration Activity

- *Drilling activity during the first half of 1990 increased slightly over the same period last year.*

- *Second-quarter activity was hampered by unusually heavy rains throughout the spring breakup.*

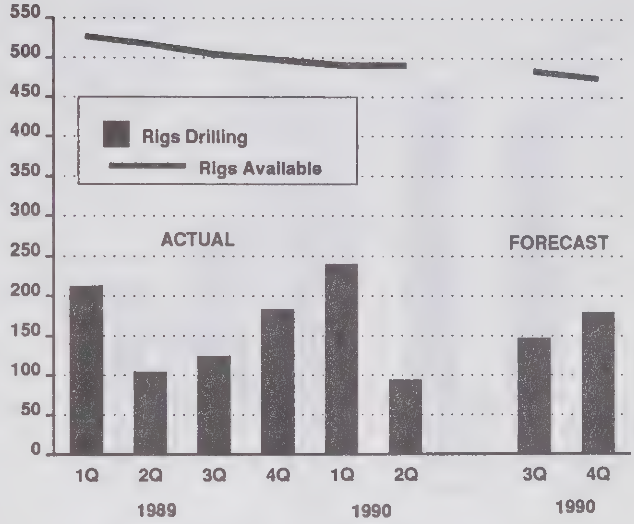
By mid year, a significant revival in Western Canada drilling activity did not materialize. In fact, drilling activity during the first half of 1990 showed very little improvement over the same six month period the year before - which proved to be one of the worst years on record for the Canadian drilling industry.

Over the first half of the year, an average of 167 of 491 available rigs were reported active, setting a rig utilization rate of about 34%. This compares with 179 of 521 active rigs a year earlier. However, this level of activity remained well below activity recorded in the first half of 1988 when 236 of 552 rigs were reported operating.

Drilling rig activity during the second quarter, traditionally the slowest quarter of the year, was lower than expected as field activity was hampered by unusually heavy rains throughout the spring breakup. Inclement weather is reported to have forced the postponement of some drilling activity which resulted in only 94 active rigs compared with 104 rigs during the second quarter of last year.

Besides spring weather conditions, the industry has been plagued by unstable oil prices, a strong Canadian dollar, high interest rates, high provincial royalty rates and reduced cash flows . Exacerbating to the situation, company mergers and acquisitions have continued to redirect spending away from drilling programs to asset management.

Figure 2.1
Drilling Rig Activity in Western Canada
(number of rigs)



By the end of the first half of 1990, 2657 exploratory and development wells (including 777 dry wells) were drilled, 2% less than the same period in 1989. Total metres drilled fell slightly to 3.2 million metres with the average well depth down by 5% to 3092 metres.

Development wells, accounting for 46% of completed wells (including dry) fell by 17% to 1223, compared with last year. Metres drilled dropped 19% to 1.2 million metres. As can be seen in figure 2.2, both oil and gas completions registered declines. However, some concern has been expressed about the 26% drop in oil completions - attributed to an almost complete absence of drilling in Alberta oil sands in situ projects.

Figure 2.2
Development Well Completions
(thousands of wells)

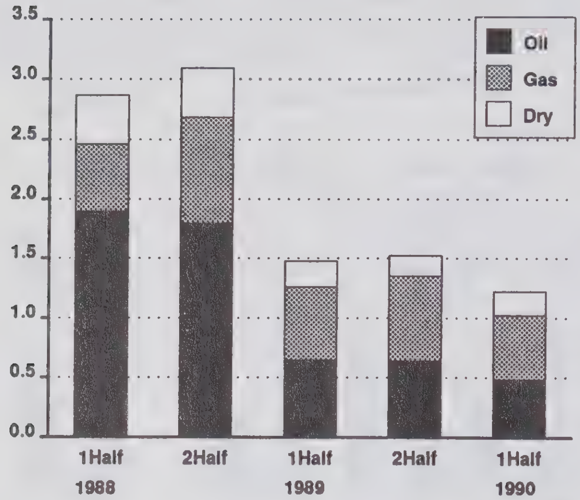
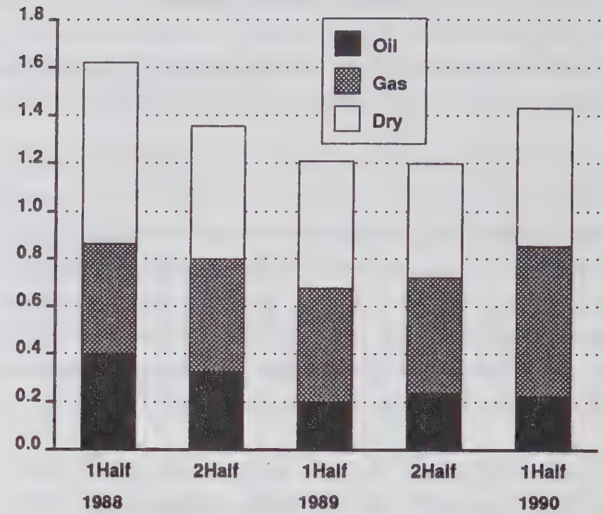


Figure 2.3
Exploratory Well Completions
(thousands of wells)



Over the same period, the number of exploratory wells, figure 2.3, increased by 19% to 1434 compared with a year earlier. Metres drilled increased by 17% to 1.6 million metres continuing a trend established during the first quarter of the year. As can be seen in figure 2.3, most of the increase in completions was the result of a 32% jump in gas well completions compared with a year earlier. Alberta dominated with a 64% jump in gas completions to 481 wells.

Although the drilling industry remains weak, the Canadian Association of Drilling Contractors (CAODC) has forecast a 1990 rig utilization of 34%, about 4 percentage points above last year. The Association reduced its earlier annual forecast by 1% but does suggest that the rate could increase if the trend towards more exploratory activity gains momentum as a result of rising demand for natural gas.

Over the second half of 1990, the CAODC expects activity to improve even though the rig fleet size is expected to drop an additional 4% to 475 available rigs. Third-quarter activity may in fact exceed 147 of 484 active rigs as drilling begins on second-quarter weather delayed projects. During the fourth quarter the number of active rigs is expected to increase to 179 of 475 rigs.

Analysts note that the 'cautious and prudent' approach adopted by most companies has had a negative impact on major development and exploration programs. Specifically, additions to oil reserves are said to be no longer replacing declining production - in particular, of light conventional crude oil.

3. Crude Oil Supply

- *Total domestic crude oil and equivalent production during the first half of 1990 averaged 255 000 m^3/d, down 4% from the year before.*

- *Second-quarter crude oil imports, at 75 000 m^3/d, were down substantially from the first quarter of the year.*

3.1 Total Crude Oil Supply

Total available supply of crude oil during the first half of 1990 averaged 340 000 m^3/d, down nearly 3% from a year earlier. Of this volume, indigenous crude oil supply (including production from Ontario, recycled diluent, and surplus Newgrade supply re-injected into the IPL system as light crude) averaged 257 000 m^3/d with crude imports accounting for the remainder. The equivalent of 30% of this total was delivered to export markets.
(*See Appendix I and III*)

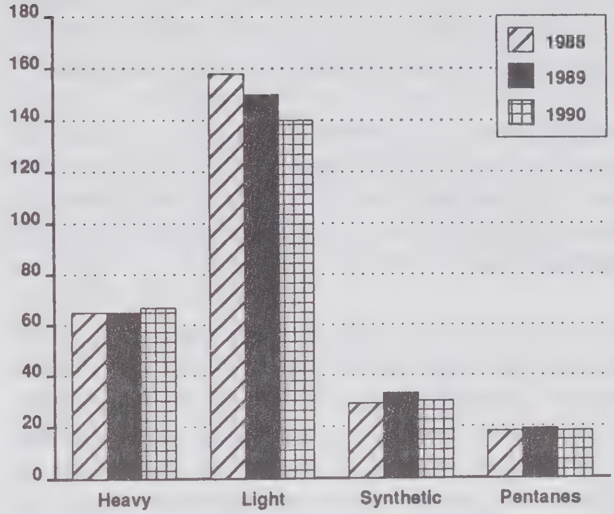
On a quarterly basis, second-quarter supply averaged 333 000 m^3/d, 258 000 m^3/d of indigenous supply and 75 000 m^3/d from offshore.

3.2 Domestic Crude Oil Production

Over the first six months of 1990, total domestic crude oil and equivalent production (including production from Ontario) averaged 255 000 m^3/d. This level represented a decline of 4% from the same period last year and 8% from the level of output recorded in 1988 when production reached its highest level in the decade.

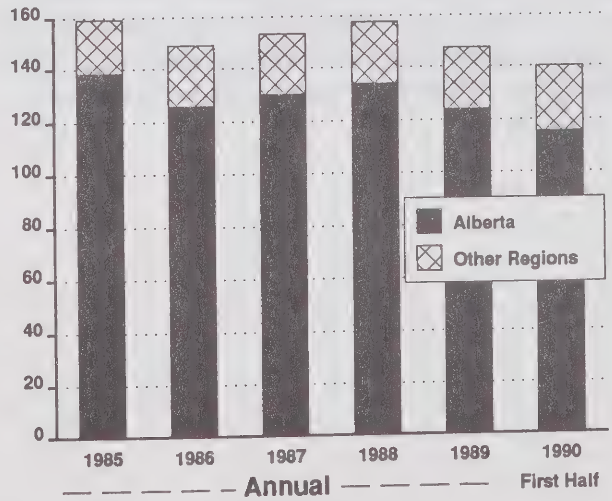
With productive capacity pegged at about 265 000 m^3/d, shut in over the first half averaged 10 000 m^3/d (8 000 m^3/d of light crude and 2 000 m^3/d of heavy).

Figure 3.2.1
Crude Oil Production
(First Half 1990)
000 m^3/d



Conventional light crude production, for the most part reflecting a natural decline in productivity of older established wells, averaged 140 000 m^3/d during the first half of 1990, 7% below last year. As can be seen in figure 3.2.2, all of the decline was recorded in Alberta where conventional light production dropped by 9% to 116 000 m^3/d. All other producing regions collectively recorded a marginal increase.

Figure 3.2.2
Conventional Light Crude Production
000 m^3/d



Synthetic crude production averaged 30 000 m^3/d, 9% less than in 1989. Production was lower than expected primarily as a result of a fire at the Syncrude plant which reduced first-quarter output by almost half. Output at both the Syncrude and Suncor plants were also affected by scheduled maintenance programs. In fact, Suncor was completely shut down in June for a major turnaround.

Pentanes plus supply, related to changes in crude oil and natural gas production, decreased by 5% to 18 000 m^3/d. Less than one third of this volume was delivered as refinery feedstock with the remainder used as heavy crude oil diluent.

Production of heavy crude oil and bitumen (unblended) averaged 67 000 m^3/d, 5% higher than the first half of last year. All of the increase occurred in conventional production (47 000 m^3/d) as a result of modest drilling activity in southern Alberta. Bitumen production held at 20 000 m^3/d as poor economics last year forced the postponement of several planned commercial in situ oil sands projects.

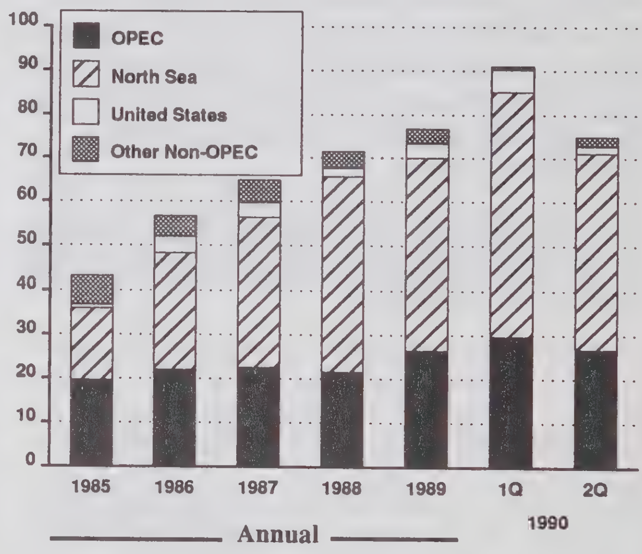
Based on recent National Energy Board (NEB) estimates, 1990 production is expected not to exceed 262 000 m^3/d, down 2% from the 266 000 m^3/d recorded in 1989. Analysts suggest that supply, at least in the near term, will likely be determined by trends in conventional light crude production. Drilling activity is thought to be insufficient to offset declining production from existing pools.

The NEB expects other domestic sources of supply to experience relative stability or modest growth. Synthetic crude production is expected to return to normal levels, about 36 000 m^3/d. Heavy (unblended) crude production, particularily from Alberta, could realize a small gain in part because of improved enhanced oil recovery techniques. No significant change is expected in bitumen production.

3.3 Crude Oil Imports

After reaching their highest level in the last several years during the first quarter of 1990, crude oil imports subsequently fell by over 15 000 m^3/d in the second quarter to 75 000 m^3/d. The decline in foreign crude oil receipts reflected the scheduled implementation of a large number of, what ended up to be, prolonged refinery turnarounds, which restricted demand for imported (as well as domestic) crude oil. *(See Appendix VI)*

Figure 3.3.1
Imports of Crude Oil by Source
000 m^3/d



In relation to the same quarter of last year, however, crude oil imports were down only 1 000 m^3/d in the second quarter. Paradoxically, receipts of domestic crude oil fell by almost 15 000 m^3/d between the same two periods, even though there was now a surfeit of indigenous light crude oil supply to domestic requirements, as evidenced by the sharp rise in light crude exports during the quarter. The relatively high level of imports in the face of a large surplus in domestic supply was a manifestation of marked inter-regional divergences in refinery turnaround activity. The decline in demand for domestic crude oil reflected the fact that this year's turnarounds was for the most part concentrated in Ontario and the Prairies, two regions whose refineries process predominantly domestic crude oil feedstocks. On the other hand, imports were maintained because of below-normal turnaround levels in the Atlantic and Quebec regions, where refineries rely mostly on imported crude oil. Moreover, in the Atlantic, certain refiners have stepped up their processing activities, whereby imported crude oil is refined for the export market. The fact that, during this year's second quarter, foreign crude appeared to be cheaper than domestic crude likely also helped raise imports to levels higher than they would otherwise have been.

About 60% of total crude oil imports came from the North Sea. In fact, except for small volumes from the United States, the North Sea accounted for almost all non-OPEC supplies. At 44 000 m^3/d, North Sea deliveries were roughly evenly split between the Atlantic and Quebec. North Sea crudes comprised 95% of Quebec imports and almost 45% of the Atlantic's. A delivery was also made to Ontario from the U.S. Gulf Coast.

OPEC supplied about 36% of Canada's import requirements during the second quarter, with deliveries approaching 27 000 m^3/d. Traditionally, the Atlantic refiners have been the major buyers of OPEC crude, as normally only small volumes are refined in Quebec. This pattern continued in the second quarter with 95% of OPEC deliveries to the Atlantic. Saudi Arabia, with deliveries averaging 9 000 m^3/d, was the largest OPEC supplier, followed closely by Nigeria. Imports from Iraq and Kuwait, on the other hand, have never been large. During the second quarter, purchases from Iraq were slightly above 2 000 m^3/d, while no crude oil was bought from Kuwait. Heavy crude oil shipments from Venezuela averaged 2 000 m^3/d.

Based on a July survey of refiners' nominations by the National Energy Board (NEB), foreign crude oil receipts are expected to rise in the latter half of 1990 by approximately 10 000 m^3/d to 93 000 m^3/d, vis-a-vis the first half of the year. This would also imply an increase for the year as a whole of almost 11 000 m^3/d over 1989, reflecting a rise of 4 000 m^3/d in the Atlantic, and of 7 000 m^3/d in Quebec. Ontario refineries, on the other hand, would drop their imports by 1 000 m^3/d from last year. The North Sea would continue to be the dominant source, accounting for almost two-thirds of total imports.

4. Crude Oil Disposition

- *High refinery turnaround activity and a smaller inventory build resulted in a significant year-over-year decline in crude oil receipts during the second quarter*

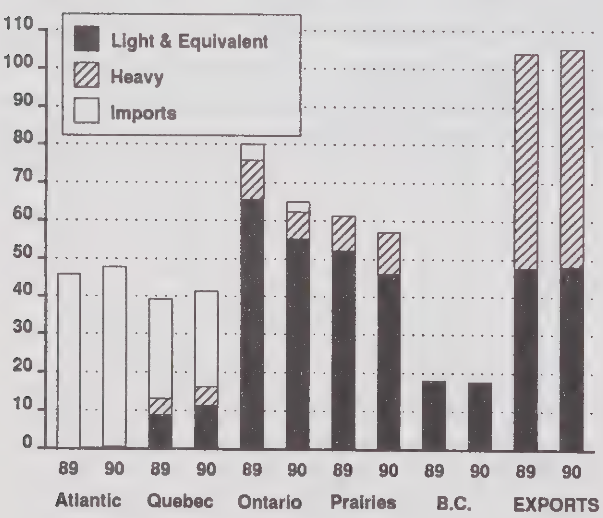
- *Crude oil receipts are expected to increase substantially during the latter half of 1990, with higher imports accounting for most of the rise.*

- *Exports during the first half of 1990 averaged 101 000 m^3/d, 4% less than a year earlier. Second quarter exports were up marginally from the year before.*

4.1 Canadian Refinery Crude Oil Receipts

Averaging just 229 000 m^3/d during the second quarter, deliveries of crude oil to Canadian refineries were almost 16 000 m^3/d, lower than during the corresponding period last year. The lower refinery receipts in part reflected a 10 000 m^3/d decline in crude runs which in turn resulted from a relatively large number of prolonged refinery turnarounds this year, particularly in Ontario. Receipts last year were also boosted when crude oil inventories were built at a rate of almost 9 000 m^3/d over the quarter. This year, by comparison, there was a build of only about 2 000 m^3/d. (*See Appendix VI*)

Figure 4.1
Disposition of Crude Oil
Second Quarter
000 m^3/d



Not all regions, however, saw a decline in their receipts. Atlantic and Quebec refiners both increased their demand for crude oil, each by about 2 000 m^3/d. The increase in the Atlantic was largely reflective of processing agreements whereby crude oil is imported and refined for the export market. Total Atlantic receipts averaged close to 48 000 m^3/d during the quarter with about a third of these receipts related to processing agreements. Except for a shipment of domestic heavy crude oil in April, Atlantic refiners relied on foreign crudes to meet their feedstock requirements.

In Quebec, crude oil imports accounted for 60% of total receipts, averaging 25 000 m^3/d. Domestic crude oil deliveries via the Sarnia-Montreal pipeline exceeded 16 000 m^3/d, the highest quarterly average since 1988. This marked a temporary reversal of a downward trend in deliveries of Canadian crudes to Quebec refiners, who have, in recent years, increasingly chosen the import option. About 30% of domestic deliveries to Quebec were of heavy crude oil.

Crude oil demand in Ontario fell by 15 000 m^3/d to 65 000 m^3/d. Domestic crudes made up 95% of the region's receipts. Heavy crude oil accounted for 11% of domestic receipts. Imports fell to below 3 000 m^3/d. Although they consisted mostly of U.S. crudes, some offshore crudes, averaging close to 1 000 m^3/d, were pipelined up from the U.S. Gulf.

Domestic oil deliveries to Prairie refineries declined by 4 000 m^3/d to 57 000 m^3/d as a result of an even steeper decline in conventional light crude oil receipts. Conventional light receipts might have been higher had not a major explosion and fire at the 20 000 m^3/d Petro-Canada refinery in Edmonton late in May forced the temporary shutdown of the refinery. As a result, throughput at the refinery was effectively cut in half during June. Prairie refinery intake of heavy crude oil, on the other hand, rose by almost 2 000 m^3/d from the year before to approach 11 000 m^3/d. This increase reflected the relatively problem-free operation of the Newgrade upgrader, which managed to process about 5 500 m^3/d of heavy crude oil during the quarter without any serious disruptions.

Refiners in British Columbia continue to rely almost exclusively on domestic light crude oil feedstocks. Crude oil receipts declined marginally to below 18 000 m^3/d.

The decline in crude oil receipts that has been observed in recent years has resulted from some limited substitution (currently about 5 000 m^3/d) of semi-refined oil pipelined, in lieu of crude oil, from Edmonton to Vancouver area refineries.

Crude oil demand is expected to increase in the second half of 1990, according to a National Energy Board survey of refiners' crude oil nominations conducted in July. Total deliveries should average about 257 000 m^3/d during the second semester, or roughly 14 000 m^3/d higher than the average recorded for the first half of the year. This would also imply, for the year as a whole, a 3% increase over the average for 1989, with most of the increase occurring in Quebec and the Atlantic.

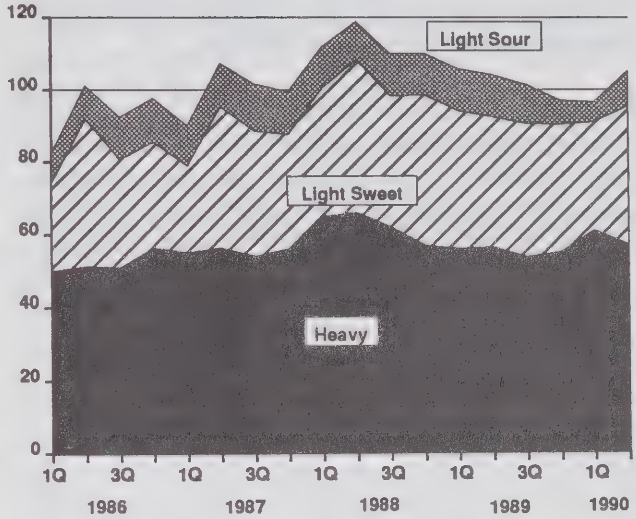
Imports are anticipated to account for most of the increase in second half receipts, averaging around 93 000 m^3/d. Domestic crude oil deliveries to Quebec should fall back to an 11 000 m^3/d range; while receipts of domestic heavy crude oil could reach a record level of 26 000 m^3/d, if the Newgrade upgrader operates without any major disruptions.

4.2 Crude Oil Exports

Exports of crude oil and equivalent during the first six months of 1990 averaged 101 000 m^3/d, 4% less than a year earlier and 13% below that recorded in 1988 - a record year for Canadian exports.

The decline in exports was primarily the result of consistent shortfalls in domestic light crude production and to a lesser extent entry into the U.S. midwest of cheaper offshore crude brought in via the U.S. Gulf.
(*See Appendix IV*)

Figure 4.2.1
Crude Oil Exports
000 m^3/d



First-half exports represented about 40% of domestic crude oil and equivalent production (73% of blended heavy supply and 27% of net light crude production). When compared with a year earlier, heavy crude exports, supported by a modest rise in production increased by 6% to 59 000 m^3/d. Exports of light crude, of which 82% was light sweet, decreased by 14% to 42 000 m^3/d.

Second-quarter exports, averaging 105 000 m^3/d were up only marginally from the second quarter of 1989 but were 9% above the first quarter, 1990 level. This rise was for the most part the result of increased availability of conventional light crude due to extended domestic refinery turnarounds during the spring and to the continuing demand for heavy crude and bitumen by U.S. refiners for the production of asphalt.

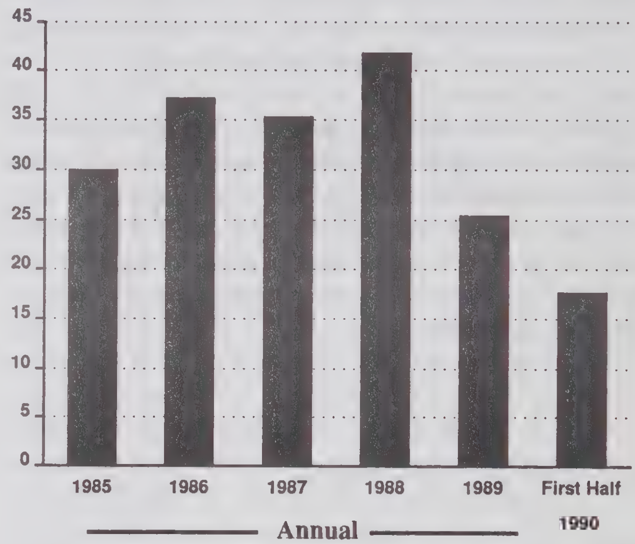
As illustrated in Appendix IV, most Canadian crude and equivalent exports were delivered to the United States with small volumes of mainly heavy crude tankered offshore. While Canadian exports to the United States have fallen steadily since early 1988, U.S. demand for imported crude oil has continued to rise.

According to the U.S. Department of Energy (DOE) crude oil imports during the first half of 1990, including crude destined for the Strategic Petroleum Reserve, reached 974 000 m^3/d, up 11 % from the same period last year. Of this volume imports from Canada represented about 10%, down from 12% the year before. Canada dropped from the fourth largest supplier of imported crude to fifth behind Saudi Arabia, Nigeria, Mexico and Venezuela and was followed closely by Iraq.

Three-quarters of Canadian exports were delivered to PAD District II, where as might be expected, most of the change in deliveries to the United States occurred. Total Canadian deliveries to PAD District II fell 2% to 75 000 m^3/d compared with a year earlier. While sales of heavy crude increased by 7% to 50 000 m^3/d, light crude exports fell by 17% to 24 000 m^3/d. Although Canada remained the number one supplier of imported crude to PAD District II, Canada's share fell from 47% to 41%.

As a consequence of the first-half drop in Canadian crude oil exports, Canada's net export position fell. As can be seen in figure 4.2.2 exports exceeded imports by about 18 000 m^3/d during the first six months of the year compared with 26 000 m^3/d over the same period in 1989. Canada's net export position has been deteriorating since 1988.

Figure 4.2.2
Net Crude Oil Export Position
000 m^3/d



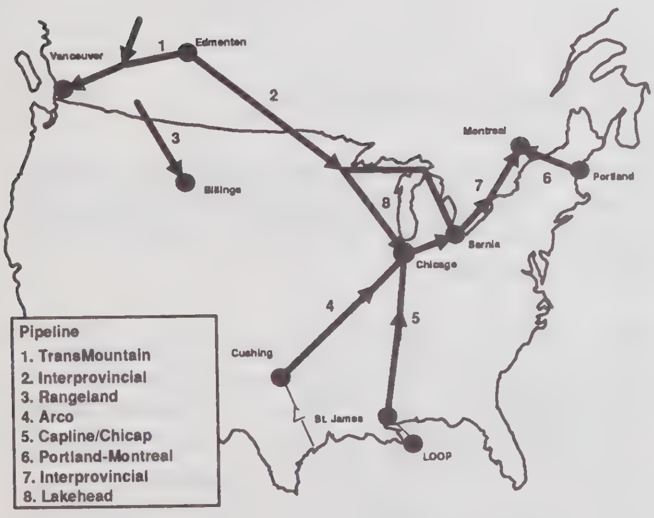
5. Pipelines

- *The lower throughput during the first half of 1990 on the two main trunklines reflected declining domestic crude oil production.*

Western Canadian crude oil is, for the most part, delivered to markets through a network of pipelines. A map illustrating major crude oil pipelines in North America is shown below.

The Trans Mountain Pipe Line and the Interprovincial Pipe Line originate in Edmonton, where most Canadian crude oil is gathered. The Rangeland pipeline supplies U.S. refiners south of the Prairie provinces. The selected American pipelines shown on the map illustrate the supply alternatives for our main export market. Chicago can be supplied with US domestic crudes from Cushing, Oklahoma, with foreign crudes through the US Gulf (LOOP), and with Canadian crudes via the Interprovincial Pipeline.

Figure 5
Major Crude Oil Pipelines In North America



5.1 Trans Mountain Pipe Line

During the second quarter of 1990, Trans Mountain Pipe Line (TMPL) throughput averaged 25 300 m^3/d, down 6% from the previous quarter. Throughput for the first half of 1990 averaged 25 800 m^3/d, a decrease of 10% compared to the same period last year.
(*See Appendix V.*)

Total deliveries of crude oil to B.C. refineries during the second quarter were 14 700 m^3/d, 1000 m^3/d higher than the first quarter. However, deliveries were still down by 1 500 m^3/d over the first half of this year compared to the same period of 1989. Deliveries of semi-refined products decreased slightly by 100 m^3/d over the second quarter to 5 000 m^3/d. Deliveries of refined products from Edmonton to Kamloops British Columbia remained stable at 2 700 m^3/d during the first two quarters of the year, the same as last year.

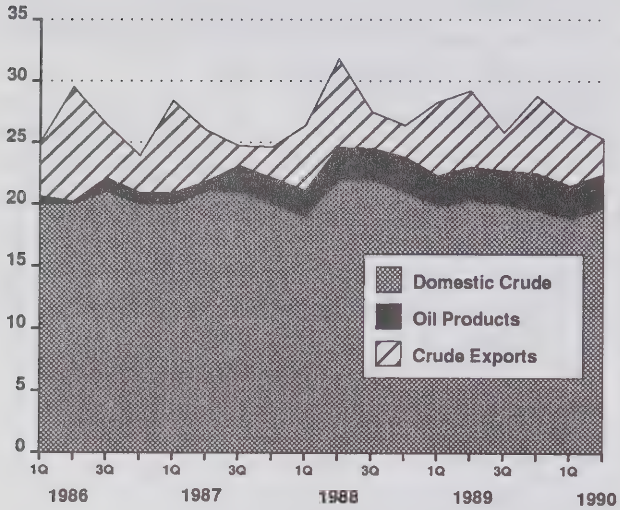
Overall, total domestic deliveries increased by 900 m^3/d or 4% over the first quarter but decreased by 1 500 m^3/d or 3% over first half of 1990 versus first half 1989.

Crude oil deliveries for export by tanker at the Westridge marine terminal averaged 1 600 m^3/d, 1 000 m^3/d less than a year ago. However, total first half deliveries were up 300 m^3/d on a year-over-year basis.

Pipeline exports from Sumas to the Puget Sound area averaged 1 300 m^3/d during this quarter representing an increase of 600 m^3/d due to an oversupply of light crude in Edmonton as several large refiners connected to the Interprovincial Pipeline were on turnaround. Compared to last year, pipeline and tanker exports for the first quarter decreased by 3 300 m^3/d.

The basic toll effective from April 21, 1990 applying to light crude oil deliveries from Edmonton to Burnaby, British Columbia was \$8.42/m^3.

Figure 5.1
Trans Mountain Deliveries
000 m^3/d



5.2 Interprovincial Pipe Line

The Interprovincial Pipe Line system consists of two connected segments, the first one is in Canada and is commonly referred to as IPL while the second, called "Lakehead", serves American markets in the Great Lakes area.

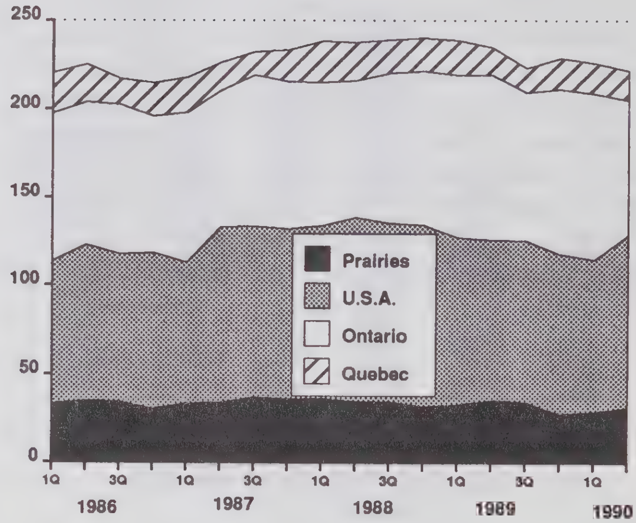
Total IPL and Lakehead deliveries of crude oil and other hydrocarbons, including petroleum products and natural gas liquids, during the second quarter of 1990, averaged 221 900 m^3/d, down 4 400 m^3/d from the previous quarter and 12 700 m^3/d from a year ago.

Total deliveries of crude oil to Canadian refineries during the first quarter were 124 200 m^3/d, 20 100 m^3/d (16%) less than a year earlier and 16 400 m^3/d lower than the first quarter of 1990. Deliveries to Canadian refiners represented 56% of IPL total throughput. Deliveries to the United States, at 97 700 m^3/d, were up 7 400 m^3/d (9%) from the same quarter the previous year.

New pipeline tolls and terminalling and tankage charges have been approved by the NEB effective April 1 through to the end of the year. The new tolls and charges represent a total increase of about \$0.85/m^3 to about \$9.03/m^3.

Other changes have also been introduced. Heavy crude movements are now subject to a surcharge of 20%, rather than 30%, over the base rate while medium crudes face a surcharge of 8% compared to 10% previously. The tariff applicable to very light products, such as gasoline and condensates, is now only 92% of the base rate versus 100% before.

Figure 5.2
Total IPL Deliveries
000 m^3/d

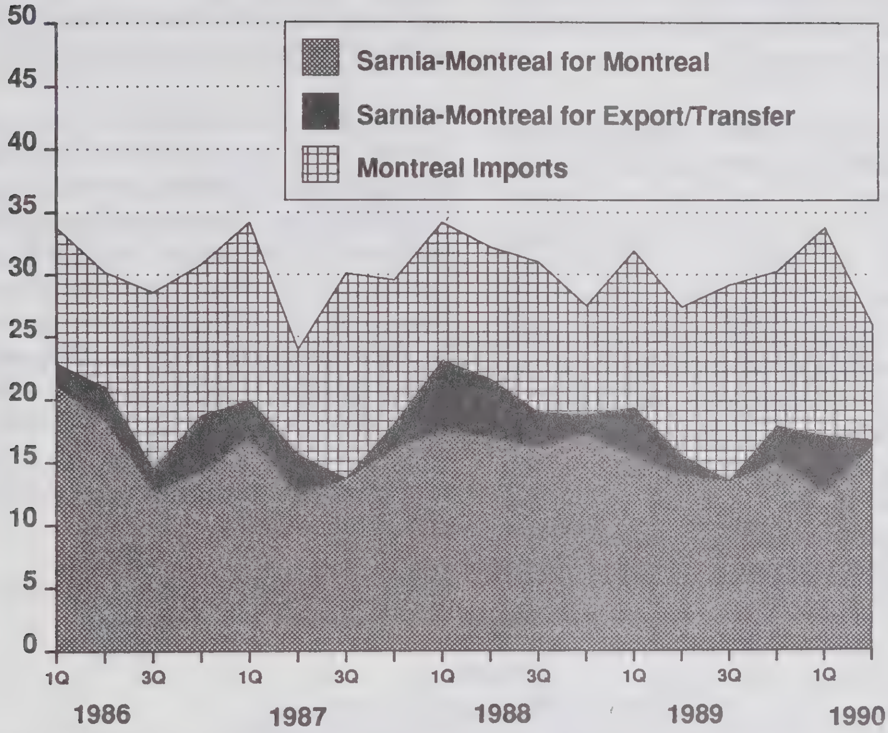


5.3 Pipelines to Montreal

Total deliveries of crude oil and equivalent to Montreal refiners, during the second quarter of 1990, averaged about 25 500 m^3/d, down 400 m^3/d from the same quarter a year earlier.

Total domestic crude deliveries via the Sarnia-Montreal portion of the IPL system averaged 16 700 m^3/d, 1 200 m^3/d more than the year before, about 16 300 m^3/d were for use by Montreal refineries with the remainder (400 m^3/d) exported. Foreign crudes, imported mainly through the Portland Pipe Line, averaged 9 200 m^3/d down 2 700 m^3/d from the same period last year.

Figure 5.3
Deliveries to Montreal
000 m^3/d



6. Refinery Throughput and Utilization Rates

- *Reflecting an above average number of turnarounds, the national refinery utilization rate fell to a two year low during the second quarter*

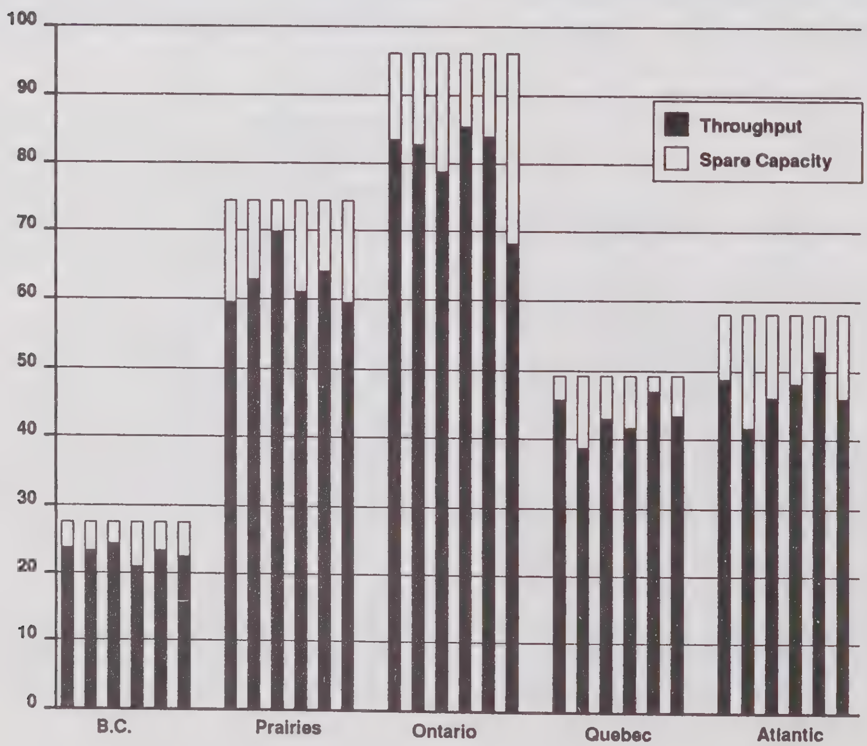
- *Utilization rates were the highest in Quebec, where several refineries were shut down in the early eighties, and lowest in Ontario*

Refinery throughput will normally diverge from refinery crude oil receipts for two reasons. First, feedstocks other than crude oil are also charged in the refining process. Some of the 'other' feedstocks include gas plant butanes (used mostly by Prairie refineries) and partially processed oil (used mostly by B.C. refineries). During the second quarter, these 'other' receipts averaged 13 000 m^3/d or about 5% of total refinery throughput in Canada.

Second, refinery throughput reflects changes in feedstock inventories. Other things being equal, an inventory drawdown will cause refinery throughput to exceed receipts - and vice versa in the case of an inventory build. During the second quarter, there was a crude oil inventory build of about 2 000 m^3/d.

During the second quarter, total throughput averaged 240 000 m^3/d, about 10 000 m^3/d lower than during the corresponding period in 1989. With total Canadian refining capacity estimated to be about 306 000 m^3/d, this level of throughput corresponded to an across Canada average refinery utilization rate of about 78%. Such a low rate of utilization has not been observed at the national level in two years. The utilization rate was highest in Quebec where it reached 88%, and lowest in Ontario, where due to unusually high turnaround activity, it fell to 71% . Figure 6.1 illustrates refinery throughputs and capacities by region, starting from the first quarter of 1989.

Figure 6.1
Refinery Utilization vs Capacity
(1st Quarter 1989 to 2nd Quarter 1990)
000 m^3/d



7. Stocks

- *Closing crude oil and petroleum product stocks were marginally higher than the level recorded a year earlier.*

As illustrated in table 7.1, closing June 1990 crude oil and petroleum product stocks totalled 14.6 million m^3, marginally higher than the same period last year. Total stocks were up 6% from levels recorded in 1988 and 11% from 1987.

Petroleum product stocks over the first half of the year, representing 80% of total inventories, increased marginally to 11.8 million m^3 while crude oil stocks decreased slightly to 2.8 million m^3.

Table 7.1
Closing Crude and Product Inventories
(End June)
000 m^3

	Crude			Product		
	1988	1989	1990	1988	1989	1990
Atlantic	1045	1129	1151	1675	1804	1959
Quebec	792	699	609	2094	2451	2535
Ontario	598	668	702	3531	3721	3293
Prairies	284	281	277	2423	2409	2689
B.C.	110	86	90	1174	1267	1278
Canada	**2289**	**2863**	**2829**	**10897**	**11652**	**11754**

As illustrated in table 7.3, most of the change in petroleum product stocks occurred in the 'other' products category (which includes such products as jet fuel, petrochemical feedstocks and asphalt). The 'main' products category remained relatively unchanged from the previous year although motor gasoline and diesel fuel fell slightly.

Table 7.2
Petroleum Product Inventories
(End June)
days

	1988	1989	1990
Main Products	7641	7821	7806
Motor Gasoline	3427	3503	3453
Heating Oil	1052	1217	1230
Diesel Fuel	2259	2243	2186
Heavy Fuel	903	858	937
Other	3256	3831	3948
Total	**10897**	**11652**	**11754**

By the end of June, the ratio of stocks to consumption for crude oil and petroleum products, represented about 65 days of consumption, down by about 1 day from a year earlier. If the Atlantic region is excluded from the calculation because a large portion of Atlantic shipments were directed to export markets and the region is not 'pipeline-connected' to domestic supplies, the ratio for the rest of Canada would have been about 59 days compared with 60 days a year earlier.

Table 7.3
Ratio of Stocks to Consumption
(End June)
days

	Crude			Product		
	1988	1989	1990	1988	1989	1990
Atlantic	42	43	40	67	69	69
Quebec	17	15	14	46	53	56
Ontario	8	9	9	46	52	44
Prairies	6	6	6	50	51	55
B.C.	4	3	3	40	48	44
Canada	**13**	**13**	**13**	**48**	**53**	**52**

The stocks above do not include estimates of crude oil held in pipeline tankage. If these stocks were included, the ratio of total stocks to consumption would increase by about 7 days to 72 days of consumption.

8. Crude Oil and Product Prices

- *WTI prices reached a low of less than US $ 16.00 per barrel by mid-June, primarily reflecting high OPEC production.*

- *Domestic and export crude oil prices continue to track international prices.*

- *Average gasoline prices in Canada reached a high of 56.4 cents per litre during the second quarter.*

8.1 International Crude Oil Prices

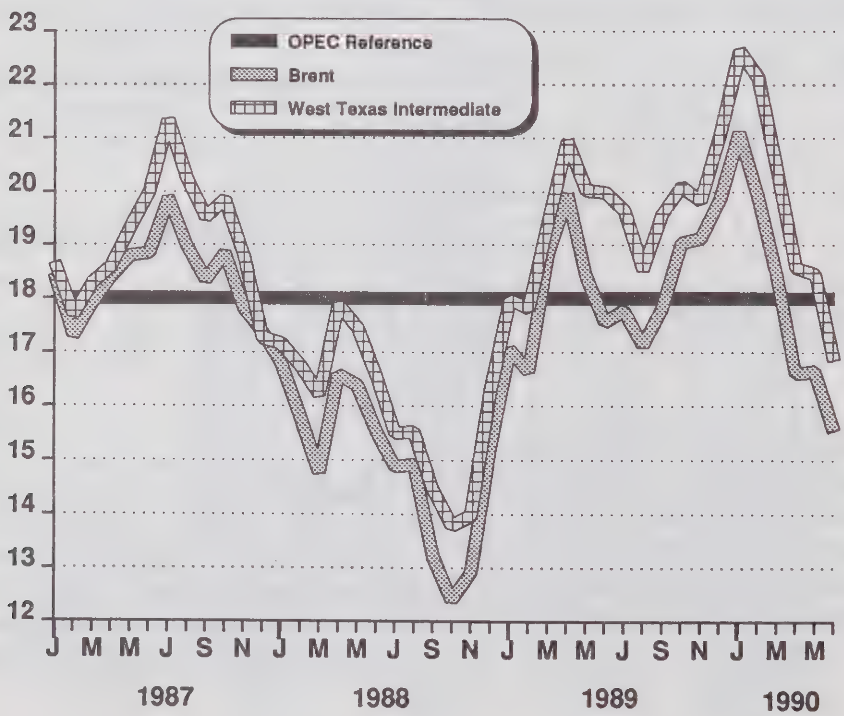
International crude oil prices, as represented by the U.S. benchmark crude West Texas Intermediate (WTI), continued their downward slide in the second quarter. WTI prices, which opened the quarter at more than US$20.00/bbl, declined to less than US$16.00/bbl by mid-June. The decline in prices is attributed to high OPEC production, normal seasonal demand reduction and increasing crude oil inventories worldwide.

In April, OPEC produced 23.5 MMB/D, 1.5MMB/D above their first half production ceiling. As the result of an early May OPEC Market Monitoring Committee, in which the chief OPEC over-producers Saudi Arabia, Kuwait and the UAE agreed to a 1 MMB/d reduction in their outputs, crude oil prices stabilized temporarily. When the May OPEC production of 23.4 MMB/D was realized and the May agreement was obviously not achieved, prices reestablished their downturn. With continuing OPEC over-production in June (23.2 MMB/D) and the resulting increased inventories, crude oil prices dropped to a low of US$15.30/bbl on June 20, rebounding in the last week to about the US$17.00/bbl.

For the second quarter, WTI prices averaged US$17.97/bbl, a decrease of US$3.74/bbl from the first quarter 1990. Over the quarter, OPEC production averaged 23.4 MMB/D, representing 1.4 MMB/D over its self-imposed production ceiling.

Figure 8.1 illustrates monthly Brent and WTI prices over the second quarter of 1990. It illustrates the decline in prices over the quarter.

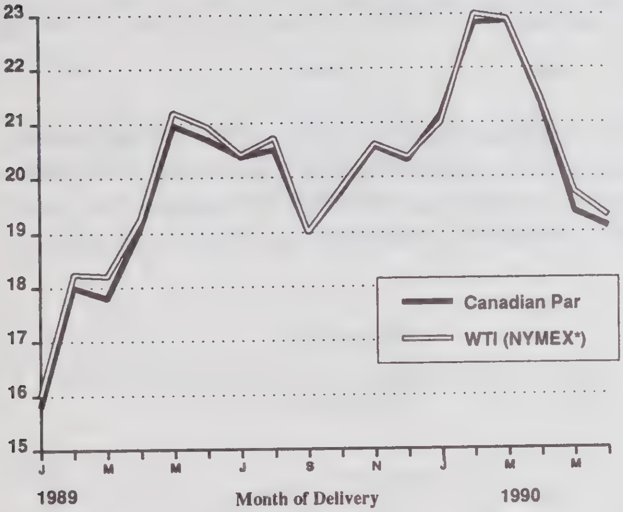
Figure 8.1
International Crude Oil Prices
US$/bbl.



8.2 Domestic Crude Oil Prices

During the second quarter of 1990, the posted price of Canadian Par crude oil (the Canadian benchmark crude at 40° API, 0.5% Sulphur) price averaged \$20.29/bbl, a decrease of \$4.73/bbl over the first quarter of 1990. The decrease can be attributed to a combination of an international oil price decrease (about \$4.20/bbl), a strenghening of the Canada/U.S. exchange rate and a slight increase of the differential between Canadian and international prices.

Figure 8.2.1
Canadian Par Crude vs WTI (NYMEX *)
at Chicago
US\$/bbl



The differential between Canadian Par and WTI NYMEX prices, on a delivered basis in Chicago, is illustrated in figure 8.2.2. The average differential in the second quarter was US\$0.29/bbl in favour of WTI NYMEX, compared to an average of US\$0.10/bbl for the first quarter. The change in the differential reflects the general oversupply of crude oil on international markets during the second quarter.

Figure 8.2.2
Canadian Par vs WTI (NYMEX *)
(Differential at Chicago)
US\$/bbl

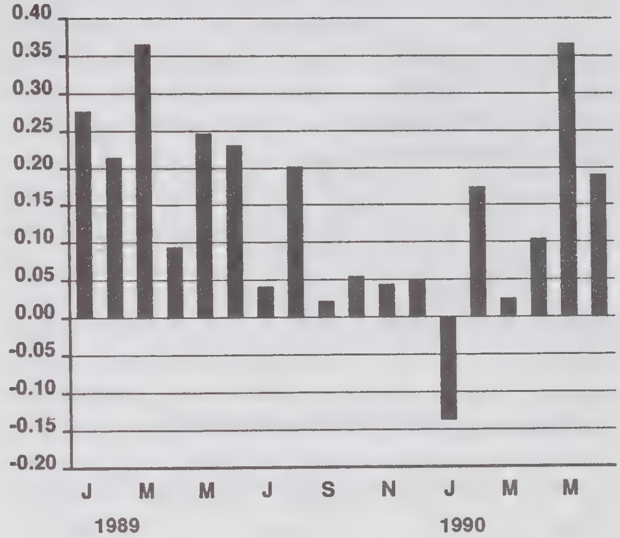
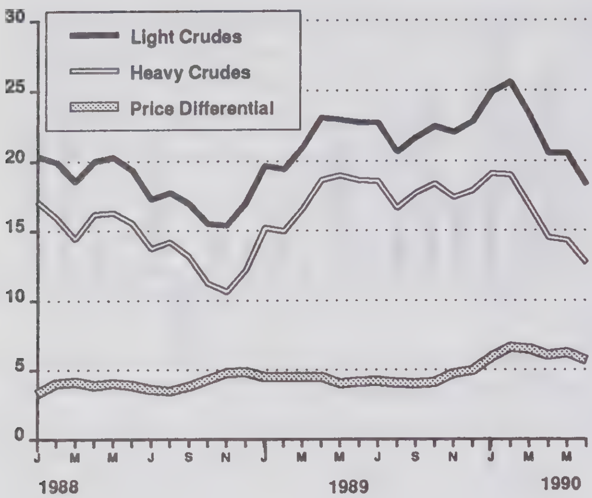


Figure 8.2.3 compares actual prices for Alberta light and heavy crude oil, purchased for use in Canada at the main trunk line injection stations. On average, reported light conventional crude oil quality during the second quarter was 37.6° API, 0.39% sulphur and blends of heavy crude were 24.6° API, 2.48% sulphur. The differential between Canadian light and heavy crude oil prices during the second quarter of 1990 was \$6.00/bbl, \$0.45/bbl lower than the first quarter differential, reflecting the short-term seasonal change in demand for heavy crude oil.

* *New York Mercantile Exchange*

Figure 8.2.3
Comparison of Domestic Light and Heavy Crude
(Actual Purchase Price- Alberta)
CAN$/bbl



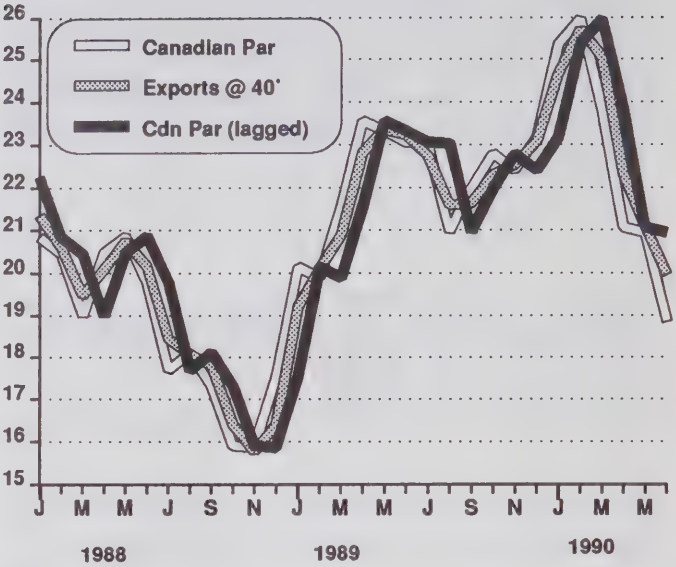
8.3 Export Prices

Figures 8.3.1 and 8.3.2 illustrate the relationship between light crude oil export prices and domestic prices.

Prices of light crude oil exported to the United States via the IPL system were netted back to Edmonton and adjusted to 40° API, on a stream by stream basis. These prices were then compared to Canadian Par crude prices, also at Edmonton.

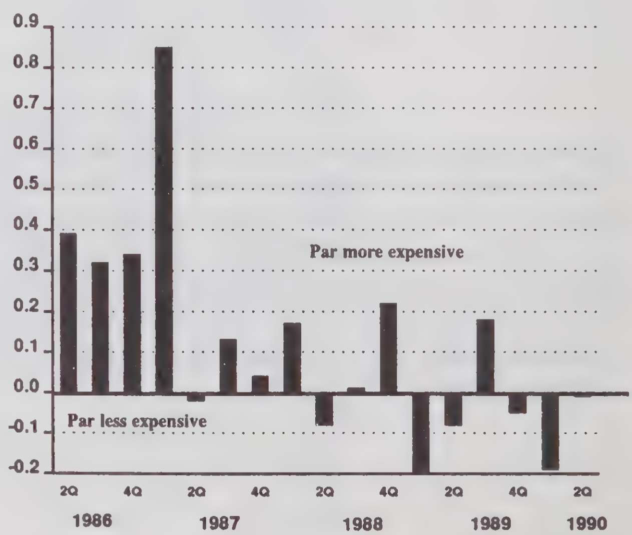
As can be observed in figure 8.3.1, in a period of declining prices, exports would appear to be more expensive than Par crude for the same month; and, in a period of increasing prices, exports would appear to be cheaper. An evaluation on that basis alone would be misleading. Canadian Par crude prices were therefore "lagged" one month to normalize for differing delivery times of export crude.

Figure 8.3.1
Light Crude Exports vs Canadian Par
CAN$/bbl



For comparison purposes, an average of the current month's Par crude and its lagged price was calculated. Figure 8.3.2 illustrates the differential between this composite average Par crude and the average export price.

Figure 8.3.2
Exports vs Canadian Par (Differential)
CAN$/bbl



8.4 Petroleum Product Prices

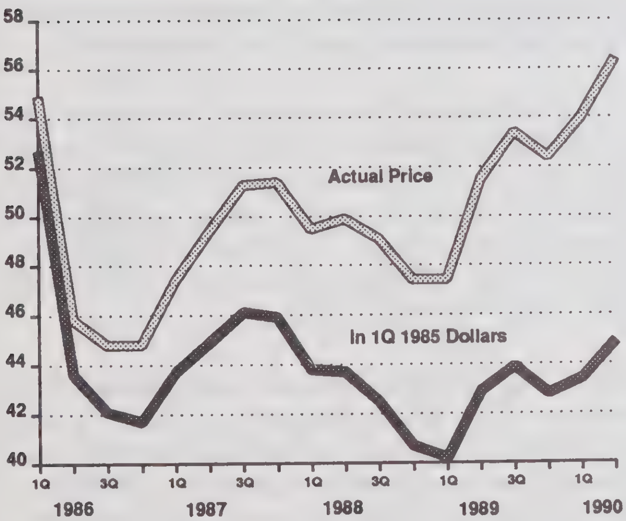
Price Trends

Gasoline and Diesel

The price of regular unleaded gasoline increased 2.4 cents per litre during the second quarter of 1990, to average 56.4 cents per litre. Although the average price is 4 cents above the price during the second quarter 1985, when the pump price, including tax, is adjusted for inflation the average price has declined 7 cents per litre or 14% over the period.

Despite a decline of 2.1 cents per litre in the average cost of crude oil during the second quarter of 1990 (June 26 versus March 27), the average price for self-serve regular unleaded gasoline increased 2 cents per litre or 3.6%. *(See Appendix VI.)*

Figure 8.4.1
Regular Unleaded Gasoline Prices
(10 City Average)
Cents/Litre



There are several factors which may have contributed to the end-June gasoline price levels. First, many Canadian refiners carried out planned maintenance on, and modifications to, processing units during the months of May and June. Some of these were related to lead phaseout and environmentally dictated product specification changes. There were also several unexpected refinery shutdowns, including two separate incidents at Petro-Canada's Edmonton refinery. These temporary reductions in refinery capacity contributed to lower gasoline supplies. Secondly, there is higher demand for gasoline during the summer months. Thirdly, refiners are attempting to improve the profitability of their operations. The Petroleum Monitoring Agency reported that return on capital employed in downstream operations (refining and marketing) fell 2 percentage points from 7.9% in 1988 to 5.9% in 1989. The tighter gasoline supplies, increased demand and attempts to improve profitability in the petroleum industry have resulted in stronger gasoline prices.

The retail price increased or remained the same in nine of the ten cities surveyed. In Winnipeg, gasoline price wars were waged throughout the quarter with the end-June price 4 cents per litre below the end-March price. In Regina and Vancouver the price was unchanged, while price increases ranged from 0.7 cents per litre in Saint John to 5.4 cents per litre in Toronto, where prices continue to be volatile.

During the second quarter of 1990, diesel prices increased an average 0.4 cents per litre to 51.6 cents per litre. Price changes ranged from a decline of 0.3 cents per litre in Toronto to a 5.6 cent per litre increase in Halifax.

Consumption Taxes on Petroleum Products

As a result of the quarterly review process, the federal sales tax increased about 0.08 cents per litre on gasoline and 0.06 cents per litre on diesel during the second quarter of 1990. The excise tax on both gasoline and diesel was unchanged. *(See Appendix VIII.)*

During the quarter, provincial taxes were increased in five provinces. In Newfoundland, Prince Edward Island, New Brunswick.and British Columbia the increases were the result of regular reviews. In Nova Scotia's April 1990 budget the ad valorem rate was increased to 22.25% on gasoline and 31.5% on diesel.

Canada vs United States

During the second quarter of 1990, the average retail price for all grades of motor gasoline increased 2.2 cents per litre in Canada compared with a 1.8 cent per litre increase in the United States. These increases are in spite of crude oil price reductions in the two countries. The differential in June was 23.1 cents per litre, up 0.4 cents per litre since March.

Higher taxes in Canada account for the bulk of the differential, about 70% in June. The balance is attributable to higher refining and marketing costs and/or profits in Canada.

Figure 8.4.2
Average Retail Price of Motor Gasoline
(Canada vs United States)
cents/litre

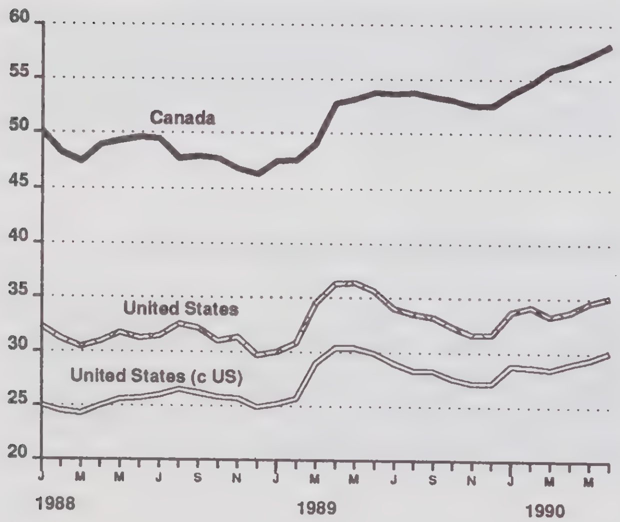
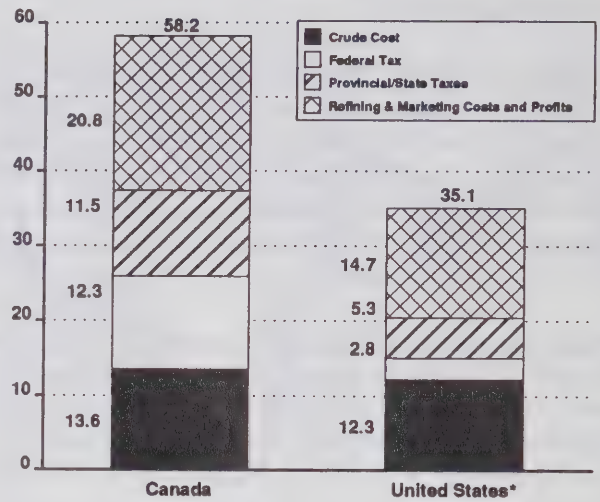


Figure 8.4.3
Breakdown of Average Pump Price
(June 1990)
cents/litre



** Exchange Rate = 1.1661*

Imperial Oil Limited Reaches Agreement on Disposition of Atlantic Assets

In February of this year, the federal government's Competition Tribunal gave the Imperial/Texaco merger the go-ahead. The Competition Tribunal is a federal government agency which has the power to consent to or reject corporate mergers on the basis of whether or not there is likely to be a substantial lessening of competition.

In order for Imperial Oil to complete its acquisition of Texaco Canada, Imperial agreed to divest all of Texaco's assets used in the wholesale and retail supply of gasoline and heating oil in the Atlantic region, including the Eastern Passage refinery in Halifax. Imperial also agreed to divest or debrand 638 service stations and divest 13 terminals across Canada.

On August 15, Imperial Oil announced it had reached an agreement with Ultramar Canada Inc. of Montreal and Island Petroleum Company of St. John's as joint purchasers of the Atlantic region refining and marketing assets of McColl-Frontenac (formerly Texaco Canada). Imperial has also reached agreement with 35 bidders for the sale of 96 company-owned stations outside Atlantic Canada. All of the agreements have been submitted for approval to the Director of Investigation and Research, Consumer and Corporate Affairs Canada.

Appendix I

Production of Canadian Crude Oil and Equivalent

		1989				1990		2Q90/	2Q90/
		2Q	3Q	4Q	Year	1Q	2Q	2Q89	1Q90
		(000 m^3/d)						(% Change)	
A.	**Light and Equivalent**								
	Alberta	123.3	122.1	121.9	124.3	119.2	111.8	*-9.3*	*-6.2*
	B.C.	4.8	4.9	6.0	5.2	5.6	5.3	*10.4*	*-5.4*
	Saskatchewan	10.3	10.6	10.5	10.6	11.2	11.6	*12.6*	*3.6*
	Manitoba	1.9	2.0	2.0	1.9	2.0	2.0	*5.3*	*0.0*
	Ontario	0.7	0.7	0.7	0.7	0.7	0.7	*0.0*	*0.0*
	Other	4.9	4.9	5.1	4.9	5.1	5.0	*2.0*	*-2.0*
	Total	**145.9**	**145.2**	**146.2**	**147.6**	**143.8**	**136.4**	***-6.5***	***-5.1***
	Synthetic								
	Suncor	9.4	9.8	8.5	9.1	9.2	5.0	*-46.8*	*-45.7*
	Syncrude	27.5	21.6	24.4	23.6	15.9	28.8	*4.7*	*81.1*
	Total	**36.9**	**31.4**	**32.9**	**32.7**	**25.1**	**33.8**	***-8.4***	***34.7***
	Pentanes Plus	**7.0**	**7.4**	**9.0**	**7.8**	**6.5**	**7.2**	***2.9***	***10.8***
	Total Light	**189.8**	**184.0**	**188.1**	**188.1**	**175.4**	**177.4**	***-6.5***	***1.1***
B.	**Heavy Crude**								
	Alberta								
	Conventionnel	24.2	25.6	27.2	25.2	24.9	26.6	*9.9*	*6.8*
	Bitumen	20.9	21.6	18.9	20.5	21.4	19.4	*7.2*	*9.3*
	Diluent*	8.0	7.7	8.0	8.2	9.3	7.5	*-6.3*	*19.4*
	Total	**53.1**	**54.9**	**54.1**	**53.9**	**55.6**	**53.5**	***0.7***	***3.8***
	Saskatchewan								
	Crude	20.1	21.5	21.7	21.1	21.0	21.3	*6.0*	*1.4*
	Diluent	2.5	2.4	2.7	2.6	3.0	2.7	*8.0*	*-10.0*
	Total	**22.6**	**23.9**	**24.4**	**23.7**	**24.0**	**24.0**	***6.2***	***0***
	Total Heavy	**75.7**	**78.8**	**78.5**	**77.6**	**79.6**	**77.5**	***2.4***	***-2.6***
C.	**Production**	**265.5**	**262.7**	**266.6**	**265.6**	**255.0**	**254.9**	***-4.0***	***0.0***
D.	**Shut-In**								
	Light	8.1	6.3	3.1	5.3	6.1	9.7	*19.8*	*59.0*
	Heavy	3.9	2.4	1.4	2.9	4.2	0.0	*-100.0*	*-100.0*
	Total	**12.0**	**8.7**	**4.5**	**8.2**	**10.3**	**9.7**	***-19.2***	***-5.8***
E.	**Total Capacity**	**277.5**	**271.5**	**271.1**	**273.9**	**265.3**	**264.6**	***-4.6***	***-0.3***

Appendix II
U.S. Petroleum Administration for Defense (PAD) Districts

Appendix III

Supply and Disposition of Canadian Crude Oil and Equivalent

	1989				1990		2Q90/	2Q90/
	2Q89	3Q89	4Q89	Year	1Q	2Q	2Q89	1Q90
	(000 m^3/d)						(% Change)	
A. Light and Equivalent								
Supply								
Production	189.8	183.9	188.0	188.1	175.4	177.4	*-6.5*	*1.1*
Newgrade	0.0	0.0	0.0	0.1	0.5	1.1	*n/a*	*120.0*
Draw/(Build)	2.5	4.6	1.4	2.8	5.7	-0.4	*-116.0*	*-107.0*
Net Supply	192.3	188.5	189.4	191.0	181.6	178.1	*-7.4*	*-1.9*
Domestic Demand								
Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	*n/a*	*n/a*
Quebec	9.1	8.0	10.4	9.3	7.1	11.4	*25.3*	*60.6*
Ontario	65.5	57.1	67.3	64.6	67.6	55.4	*-15.4*	*-18.0*
Prairies	52.4	57.7	51.9	52.7	53.7	46.0	*-12.2*	*-14.3*
B.C.	17.6	18.1	16.3	17.3	17.7	17.4	*-1.1*	*-1.7*
Total	**144.6**	**140.9**	**145.9**	**143.9**	**146.0**	**130.2**	***-10.0***	***-10.8***
Exports	**47.7**	**47.7**	**43.5**	**47.2**	**35.6**	**48.0**	***0.6***	***34.8***
Total Demand	**192.3**	**188.6**	**189.4**	**191.1**	**181.6**	**178.2**	***-7.3***	***-1.9***
B. Heavy Crude (Blended)								
Supply								
Production	75.7	78.9	78.6	77.7	79.6	77.6	*2.5*	*-2.5*
Recycled	1.3	1.4	1.1	1.2	0.5	1.3	*0.0*	*160.0*
Draw/(Build)	3.7	-4.1	-3.9	-1.1	2.6	2.0	*-45.9*	*-23.1*
Net Supply	80.7	76.2	75.8	77.8	82.7	80.9	*0.2*	*-2.2*
Domestic Demand								
Atlantic	0	0	0.1	0.1	0	0.4	*n/a*	*n/a*
Quebec	4.2	4.4	3.7	4.3	5.1	4.9	*16.7*	*-3.9*
Ontario	10.4	9.1	9.4	9.7	8.9	7.0	*-32.7*	*-21.3*
Prairies	9.1	8.5	4 .8	7.3	7.3	11.1	*22.0*	*52.1*
B.C.	0.6	0.5	0.8	0.6	0.2	0.3	*-50.0*	*50.0*
Total	**24.3**	**22.5**	**18.9**	**21.9**	**21.6**	**23.6**	***-2.9***	***9.3***
Exports	**56.3**	**53.7**	**56.8**	**55.7**	**61.1**	**57.3**	***1.8***	***-6.2***
Total Demand	**80.6**	**76.2**	**75.7**	**77.6**	**82.7**	**80.9**	***0.4***	***-2.2***

Appendix IV
Crude Oil Exports by Destination

U.S. PAD* Districts		1989 2Q	1989 3Q	1989 4Q	1989 Year	1990 1Q	1990 2Q	2Q90 2Q89	2Q90 /1Q90
		(000 m^3/d)						(% Change)	
PADD I	Light	7.4	7.2	7.5	7.4	6.3	7.8	*5.4*	*23.8*
	Heavy	1.1	1.2	1.2	1.3	1.8	1.1	*0.0*	*-38.9*
	Total	**8.5**	**8.4**	**8.7**	**8.7**	**8.1**	**8.9**	***4.7***	***9.9***
PADD II	Light	27.6	26.9	24.5	27.3	19.0	29.2	*5.8*	*53.7*
	Heavy	47.0	49.2	50.0	48.3	50.5	50.3	*7.0*	*-0.4*
	Total	**74.6**	**76.1**	**74.5**	**75.6**	**69.5**	**79.5**	***6.6***	***14.4***
PADD III	Light	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*	*0.0*
	Heavy	2.8	0.0	1.2	1.5	3.3	1.4	*50.0*	*-57.6*
	Total	**2.8**	**0.0**	**1.2**	**1.5**	**3.3**	**1.4**	***-50.0***	***-57.6***
PADD IV	Light	8.6	10.6	8.9	9.1	9.0	9.5	*10.5*	*5.6*
	Heavy	3.3	2.6	1.5	2.7	2.3	2.9	*-12.1*	*26.1*
	Total	**11.9**	**13.2**	**10.4**	**11.8**	**11.3**	**12.4**	***4.2***	***9.7***
PADD V	Light	3.7	2.1	2.5	2.8	0.7	1.3	*-64.9*	*85.7*
	Heavy	0.7	0.8	0.4	0.6	0.8	0.8	*14.3*	*0.0*
	Total	**4.4**	**2.9**	**2.9**	**3.4**	**1.5**	**2.1**	***-52.3***	***40.0***
U.S.	**Light**	**47.3**	**46.8**	**43.4**	**46.6**	**35.0**	**47.8**	***1.1***	***36.6***
	Heavy	**54.9**	**53.8**	**54.3**	**54.4**	**58.7**	**56.5**	***2.9***	***-3.8***
	Total	**102.2**	**100.6**	**97.7**	**101.0**	**93.7**	**104.3**	**2.1**	**11.3**
Offshore	Light	0.4	0.0	0.0	0.4	0.4	0.0	*-100.0*	*-100.0*
	Heavy	1.4	0.9	2.5	1.4	2.5	0.8	*42.9*	*-68.0*
	Total	**1.8**	**0.9**	**2.5**	**1.8**	**2.9**	**0.8**	***-55.6***	***-72.4***
Exports	**Light**	**47.7**	**47.7**	**43.4**	**47.0**	**35.4**	**47.8**	***0.2***	***35.0***
	Heavy	**56.3**	**53.8**	**56.8**	**55.8**	**61.2**	**57.3**	***1.8***	***-6.4***
Exports	**Total**	**104.0**	**101.5**	**100.2**	**102.8**	**96.6**	**105.1**	***1.1***	***8.9***

* *U.S. Petroleum Administration for Defense (PAD) Districts*

Appendix V
Pipeline Deliveries

	1989 2Q	1989 3Q	1989 4Q	1989 Year	1990 1Q	1990 2Q	2Q90/ 2Q89	2Q90/ 1Q90
	(000 m^3/d)						(% Change)	
A. Trans Mountain Pipe Line (TMPL)								
Domestic Deliveries								
Light Crude Oil	15.1	14.3	12.9	13.9	13.5	14.4	*-4.6*	*4.7*
Heavy Crude Oil	0.6	0.5	0.5	0.6	0.2	0.3	*-50.0*	*-60.0*
Semi Refined Products	4.7	5.2	6.2	5.4	5.1	5.0	*6.4*	*-17.7*
Refined Products	2.7	2.7	3.0	2.7	2.7	2.7	*0.0*	*-10.0*
Total	**23.1**	**22.7**	**22.6**	**22.7**	**22.5**	**22.4**	***-3.0***	***-4.9***
Foreign Deliveries								
Tankers	2.6	1,2	3,8	2.7	4.4	1.6	*-38.5*	*15.8*
Puget Sound Area	3.6	1.9	2.4	2.7	0.7	1.3	*-63.9*	*-70.8*
Total	**6.2**	**3.1**	**6.2**	**5.4**	**5.4**	**2.9**	***-53.2***	***-17.7***
Total TMPL	**29.3**	**25.8**	**28.8**	**28.1**	**26.6**	**25.3**	***-13.7***	***-7.6***
B. Interprovincial Pipe Line (IPL)								
Domestic Deliveries								
Light Crude Oil	95.8	91.0	94.9	93.9	93.3	78.7	*-17.8*	*-1.7*
Heavy Crude Oil	21.8	15.9	16.1	17.9	19.7	17.5	*-19.7*	*22.4*
Other (1)	26.7	25.0	27.6	26.4	27.6	28.0	*4.9*	*0.0*
Total	**144.3**	**131.9**	**138.6**	**139.9**	**140.6**	**124.2**	***-13.9***	***1.4***
Foreign Deliveries (2)								
Light Crude Oil	42.2	41.2	38.9	42.0	33.4	46.3	*9.7*	*-14.1*
Heavy Crude Oil	48.1	50.1	51.4	49.6	52.3	51.4	*6.9*	*1.8*
Total	**90.3**	**91.3**	**90.3**	**91.6**	**85.7**	**97.7**	***8.2***	***-5.1***
Total IPL	**234.6**	**223.2**	**228.9**	**231.5**	**226.3**	**221.9**	***-5.4***	***-1.1***
C. Pipeline to Montreal								
IPL Deliveries								
To Montreal Refineries	14.0	13.5	15.1	14.5	12.5	16.3	*16.4*	*-17.2*
For Export/Transfer	1.5	0.0	2.5	2.0	4.5	0.4	*-73.3*	*80.0*
Total IPL	**15.5**	**13.5**	**17.6**	**16.4**	**17.0**	**16.7**	***7.7***	***-3.4***
Portland-Montreal								
Montreal Imports (3)	11.9	15.7	12.5	13.2	16.8	9.2	-22.7	*34.4*
Total Mtl Receipts	**25.9**	**29.2**	**27.6**	**27.6**	**29.3**	**25.5**	*-1.5*	*6.2*

Note (1): includes petroleum products and NGL's.
(2): includes US domestic crudes delivered to the US.
(3): includes cargoes imported directly into Montreal

Appendix VI
Refinery Receipts

		1989				1990		2Q90/	2Q90/
		2Q	3Q	4Q	Year	1Q	2Q	2Q89/	1Q90/
		(000 m^3/d)						(% change)	
A.	**Domestic Feedstock Receipts**								
	Light & Equivalent								
	Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	*n/a*	*n/a*
	Quebec	9.0	8.0	10.4	9.3	7.1	11.4	*26.7*	*60.6*
	Ontario	65.5	57.2	67.3	64.6	67.5	55.3	*-15.6*	*-18.1*
	Prairies	52.3	57.7	51.8	52.7	53.7	46.0	*-12.0*	*-14.3*
	B.C.	17.6	18.1	16.3	17.3	17.6	17.4	*-1.1*	*-1.1*
	Canada	**144.4**	**141.0**	**145.8**	**143.8**	**145.9**	**130.1**	***-9.9***	***-10.8***
	Heavy								
	Atlantic	0.0	0.0	0.1	0.0	0.0	0.4	*n/a*	*n/a*
	Quebec	4.2	4.4	3.7	4.3	5.2	4.9	*16.7*	*-5.8*
	Ontario	10.4	9.1	9.4	9.7	8.8	7.0	*-32.7*	*-20.5*
	Prairies	9.1	8.5	4.9	7.3	7.4	11.1	*22.0*	*50.0*
	B.C.	0.5	0.5	0.8	0.6	0.2	0.3	*-40.0*	*50.0*
	Canada	**24.2**	**22.5**	**18.9**	**21.9**	**21.6**	**23.7**	***-2.1***	***9.7***
	Other Receipts*								
	Atlantic	0.8	0.2	0.5	0.8	0.8	0.5	*-37.5*	*-37.5*
	Quebec	0.8	1.5	1.1	1.2	1.4	1.1	*37.5*	*-21.4*
	Ontario	4.0	4.3	4.8	4.3	3.3	3.9	*-2.5*	*18.2*
	Prairies	2.7	3.4	4.0	3.4	3.4	2.6	*-3.7*	*-23.5*
	B.C.	5.2	5.7	5.9	5.9	5.3	5.0	*-3.8*	*-5.7*
	Canada	**13.5**	**15.1**	**16.3**	**15.5**	**14.2**	**13.1**	***-3.0***	***-7.7***
	Total Domestic								
	Atlantic	0.8	0.2	0.6	0.8	0.8	0.9	*12.5*	*12.5*
	Quebec	14.0	13.9	15.2	14.8	13.7	17.4	*24.3*	*27.0*
	Ontario	79.9	70.6	81.5	78.6	79.6	66.2	*-17.1*	*-16.8*
	Prairies	64.1	69.6	60.7	63.4	64.5	59.7	*-6.9*	*-7.4*
	B.C.	23.3	24.3	23.0	23.7	23.1	22.7	*-2.6*	*-1.7*
	Canada	**182.1**	**178.6**	**181.0**	**181.1**	**181.7**	**166.9**	***-8.3***	***-8.1***
B.	**Crude Oil Imports**								
	Atlantic	45.7	45.7	47.6	46.3	50.7	47.3	*3.5*	*-6.7*
	Quebec	26.0	26.6	25.5	26.5	35.2	25.0	*-3.8*	*-29.0*
	Ontario	4.2	8.0	2.9	4.2	5.1	2.6	*-38.1*	*-49.0*
	Prairies	0.0	0.0	0.0	0.0	0.0	0.0	*n/a*	*n/a*
	B.C.	0.0	0.0	0.0	0.0	0.0	0.0	*n/a*	*n/a*
	Canada	**75.9**	**80.3**	**76.0**	**77.0**	**91.0**	**74.9**	***-1.3***	***-17.7***
C.	**Total Receipts**								
	Atlantic	46.5	45.9	48.2	47.0	51.5	48.2	*3.7*	*-6.4*
	Quebec	40.0	40.5	40.7	41.3	48.9	42.4	*6.0*	*-13.3*
	Ontario	84.1	78.6	84.4	82.8	84.7	68.8	*-18.2*	*-18.8*
	Prairies	64.1	69.6	60.7	63.4	64.5	59.7	*-6.9*	*-7.4*
	B.C.	23.3	24.3	23.0	23.7	23.1	22.7	*-2.6*	*-1.7*
	Canada	**258.0**	**258.9**	**257.0**	**258.1**	**272.7**	**241.8**	***-6.3***	***-11.3***

** Partially processed oil, gas plant butanes etc.*

Appendix VII

Average Regular Unleaded Gasoline Prices

(Self-Serve)

1989-1990

	1989			1990		
	June 27	Sept. 26	Dec. 26	March 27	June 26	% Change 12 mo.
	cents per litre					
St. John's (NFLD)	56.3	56.7	56.8	58.3	59.6	*5.9*
Charlottetown	51.5	54.1	53.8	56.2	57.7	*12.0*
Halifax *	52.4	52.4	52.4	53.8	57.5	*9.7*
Saint John (N.B.)*	53.3	53.9	51.9	55.2	55.9	*4.9*
Montreal	58.1	58.1	58.1	60.8	61.9	*6.5*
Toronto	50.1	51.3	47.2	48.5	53.9	*-7.6*
Winnipeg	50.9	51.4	50.7	53.9	49.9	*-2.0*
Regina	53.9	53.8	45.8	54.9	54.9	*1.9*
Calgary	48.2	48.1	48.1	51.9	53.3	*10.6*
Vancouver	53.6	54.1	54.9	59.9	59.9	*11.8*
Canadian Average	**53.1**	**53.6**	**52.1**	**54.8**	***56.8***	*7.0*
Consumption taxes included:						
Federal	11.1	11.0	11.0	12.1	12.1	*9.0*
Provincial	10.4	10.5	10.6	11.3	11.4	*9.6*

** Full-serve*

Appendix VIII

Consumption Taxes on Petroleum Products

(June 1, 1990)

	Ad valorem		Gasoline			
	Mogas	Diesel	Reg L	Reg UL	Prem UL	Diesel
	(%)		(cents per litre)			
FEDERAL TAXES						
Sales			3.63*	3.63*	3.74*	2.77*
Excise			9.5	8.5*	8.5	4.0
PROVINCIAL TAXES						
Newfoundland [(a)]	*23* [(b)]	*27*	12.8*	11.3*	11.3*	12.5*
Prince Edward Island	*23*	*26*	10.8*	10.8*	10.8*	10.6*
Nova Scotia	*22.25**	*31.5**	10.9*	10.9*	10.9*	14.1*
New Bunswick	*24.5* [(c)]	*31.5*	12.7*	10.7*	11.3*	11.4*
Quebec [(d)]			14.4	14.4	14.4	12.45
Ontario			14.3	11.3	11.3	10.9
Manitoba			10.8*	9.0	9.0	9.9
Saskatchewan			12.0	10.0	10.0	10.0
Alberta			7.0	7.0	7.0	7.0
British Columbia [(e)]	*22.5* [(f)]		11.49*	9.49*	9.49*	9.93*
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	*17*	*(g)*	8.5	8.5	8.5	7.2

(a) The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay in Labrador

b) This applies to unleaded gasoline. The tax on leaded gasoline is 1.5 cents per litre higher than the unleaded tax.

c) This applies to all gasoline. There is also a 2.2 cent per litre surcharge on regular leaded gasoline.

d) Reduced by varying amounts in certain remote areas and within 20 kilometers of the provincial and U.S. borders

e) Additional transit tax of 3.0 cents per litre in Vancouver.

d) This applies to unleaded gasoline. Taxes on leaded gasoline and diesel fuel is 2.0 and 0.44 cents per litre higher, respectively, than the unleaded tax.

g) 85% of gasoline tax.

** Changed since last quarter.*

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional area	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Shut-in capacity	The unused production capability of currently producing oil and gas wells plus the total production capability of all shut-in oil and gas wells, regardless of whether or not they are connected to surface gathering and production facilities.
Synthetic crude oil	Crude oil produced treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

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Publications

The Canadian Oil Market

Vol. VI, No. 3, Fall 1990

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Canada

THE ENERGY OF OUR RESOURCES

THE POWER OF OUR IDEAS

THE CANADIAN OIL MARKET

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Canadian Oil Markets and Emergency Planning Division
Energy Sector
Energy, Mines and Resources Canada

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The Canadian Oil Market

Overview

A review of developments in the Canadian oil industry during the third quarter of 1990 is included in this issue, and short-term outlooks have been included. The period was one characterized by higher demand and production domestically and the impact of the commencement of Persian Gulf crisis internationally.

It was determined at the onset of the Persian Gulf crisis that Canada's oil supply situation was more than adequate to meet domestic requirements. However, consideration was given to Canada's international obligations as a member of the International Energy Agency (IEA).

Canada agreed with an initial IEA recommendation, following a meeting late in September, that member countries should proceed with emergency preparations and enact a standby readiness to implement stockdraw and/or demand restraint measures in the event that further significant supply disruptions occurred.

On the domestic scene, the uncertainty generated by the Gulf situation was most evident in the rapid rise of crude oil prices during August and September. Refined petroleum product prices began to increase across Canada in response to rising crude oil costs.

Producers during the third quarter recorded a substantial increase in revenues as a result of the rise in crude oil prices. However, this additional revenue did not immediately translate into renewed interest in drilling activity, as much of this revenue was apparently directed to servicing debt.

Domestic sales of refined petroleum products increased. The rise may have been due to increased stockbuilding by wholesalers and end-users in anticipation of possible shortages and rising prices ensuing from the Iraqi invasion. On the other hand, by the end of the quarter, stocks of crude oil and petroleum products held by refiners and distributors were drawndown to about 58 days of supply.

Crude oil deliveries to Canadian refiners rebounded during the quarter as both domestic and imported receipts increased. Although domestic deliveries jumped in Ontario, deliveries to Montreal via the Sarnia-Montreal pipeline (operating at about 30% of capacity) remained steady.

While exports of domestic crude remained stable, imports rose significantly. The Persian Gulf crisis had little effect on the level and origin of imports as about sixty five percent of Canada's import requirements were supplied by non-OPEC sources. Saudi Arabia and Nigeria were the major suppliers of OPEC crude. No significant volumes were imported from Iraq or Kuwait.

The Canadian Oil Market

1. Refined Petroleum Product Demand

- *Seasonally adjusted sales of petroleum products rose during third quarter of 1990.*
- *Consumer stocks of light and heavy fuel oils appear to have been built in anticipation of rising prices.*

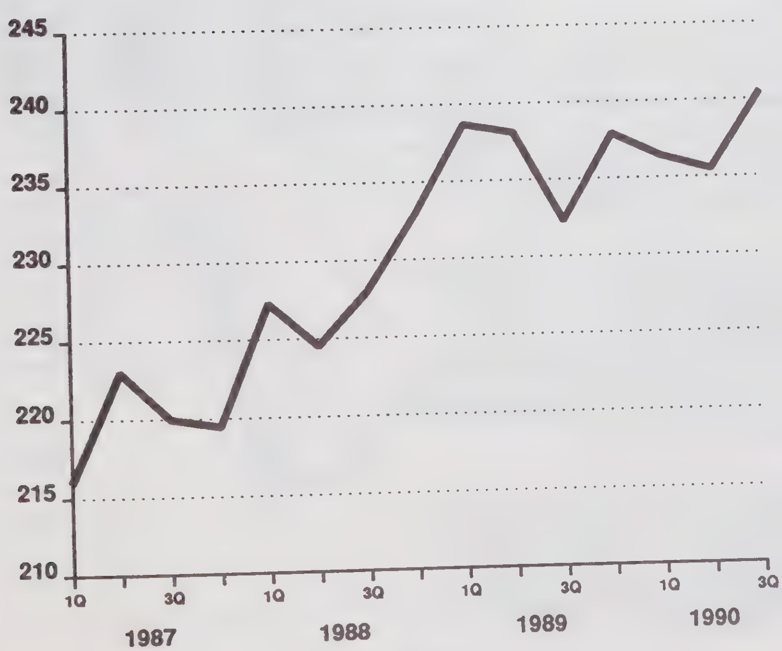
1.1 Seasonally Adjusted Demand

Consumption of refined petroleum products rose to about 240 000 m^3/d during the third quarter of 1990, according to preliminary data collected and seasonally adjusted by Statistics Canada. This represented an increase of about 2% over the second quarter of 1990, and 4% over the same period in 1989.

The third-quarter rise in product demand, as displayed in figure 1.1, reversed a downward trend that began in 1989. The gain was attributed, in part, to consumers increasing their stocks of light and heavy fuel oil in anticipation of rising prices ensuing from the Persian Gulf crisis.

Sales of light fuel oils were particularly strong at 23 000 m^3/d, representing an increase of 11% over sales during the first half of 1990. Compared with the same period in 1989, sales were 23% higher. As well, figures for heavy fuel oil showed demand at close to 31 000 m^3/d, an increase of 7% over the first half of the year.

Figure 1.1
Total Refined Product Consumption
(Seasonally Adjusted)
000 m^3/d



Many commercial and industrial light and heavy fuel oil users have significant storage capacity. Much of the increased demand in the third quarter may have reflected stock build by end users in August and early September in anticipation of higher prices during the upcoming heating season.

Motor gasoline consumption remained flat at about 94 000 m^3/d as prices at the pump began to rise. Diesel oil rose to 48 000 m^3/d, 4% over the first half of the year.

The 'other' products category which includes such products as petrochemical feedstocks, lubes, asphalts, coke, liquid petroleum gases and jet fuels, recorded a slight decline of 3% from the first half of the year to 45 000 m^3/d.

1.2 Regional Demand

Total product consumption, before seasonal adjustment, climbed to 243 000 m^3/d during the third quarter of 1990, an increase of nearly 2% from the same period in 1989. In contrast to the Atlantic region where sales remained stable and Quebec where sales suffered a decline of 3%, all other regions recorded some expansion in demand. Demand in the Prairies increased 8% to 55 000 m^3/d while in Ontario and British Columbia sales increased to 78 000 m^3/d and 29 000 m^3/d respectively, a rise of about 2% in both regions.

Nationally, light fuel oil sales were particulary strong at nearly 10 000 m^3/d, recording an 18% increase over the year before. Demand in the Atlantic region and Ontario averaged 2 000 m^3/d, up 18% over third quarter of 1989. An increase of almost 30% occurred in Quebec.

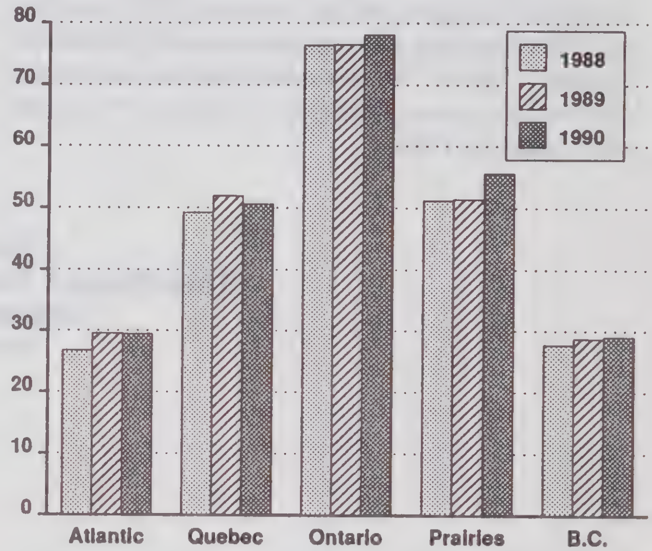
In transportation fuels, growth rates of 1% to 2% recorded in diesel fuel demand in the Atlantic region, Quebec and British Columbia were dwarfed by a dramatic 13% gain in the Prairies to 17 000 m^3/d. The surge may have reflected an increase in activity in the agricultural and energy sectors.

Motor gasoline sales in the Atlantic region remained stable at 9 000 m^3/d. Consumption in Ontario, Quebec and British Columbia fell by almost 6% to 36 000 m^3/d, 21 000 m^3/d and 11 000 m^3/d respectively. The Prairies registered a 6% increase to 22 000 m^3/d.

On a national basis, heavy fuel oil sales remained stable at 23 000 m^3/d. The 'other' products category averaged 55 000 m^3/d unchanged from year before.

Figure 1.2 compares regional demand during the third quarter of 1990 with the two previous years.

Figure 1.2
Regional Product Demand
(Third Quarter)
000 m^3/d



2. Drilling and Exploration Activity

- *Over capacity in the drilling industry continued through the third quarter of 1990 with 3 out of every 10 drilling rigs active in Western Canada.*

- *The Persian Gulf situation had little impact on the drilling industry with most producers favouring oil price stability to higher crude oil prices per se.*

A small increase in drilling activity developed during the third quarter of 1990. This increase for the most part reflected the startup of some second-quarter drilling programs deferred by an unusually wet spring. An average of 144 of an available 482 rigs were reported active only slightly better than that recorded a year earlier when 124 of an available 505 rigs were operating.

Over the first three quarters of the year, 4229 exploratory and development wells (including dry wells) were completed, 5% more than the corresponding period last year. The total number of metres drilled increased by 8% to 5.04 million with an average well depth of 3092 metres. Third quarter completions totalled 1572, 30% more than the same quarter last year with the number of metres drilled up 27% to 1.86 million metres.

Exploratory well completions increased by 17% to 2071. Despite stronger oil prices, the favoured target of producers was natural gas. While total oil well completions increased by 12% to 344, gas completions jumped 27% to 879 with most of the increase recorded in the shallow gas plays of northeast British Columbia and the Alberta foothills.

On the other hand, development well completions decreased 4% to 2158. While gas dropped 13% to 905, oil increased 2% to 944 with the largest part of the increase recorded in Saskatchewan, the result of that provinces attractive royalty structure on horizontal drilling programs.

Figure 2.1
Drilling Activity in Western Canada
(number of active rigs)

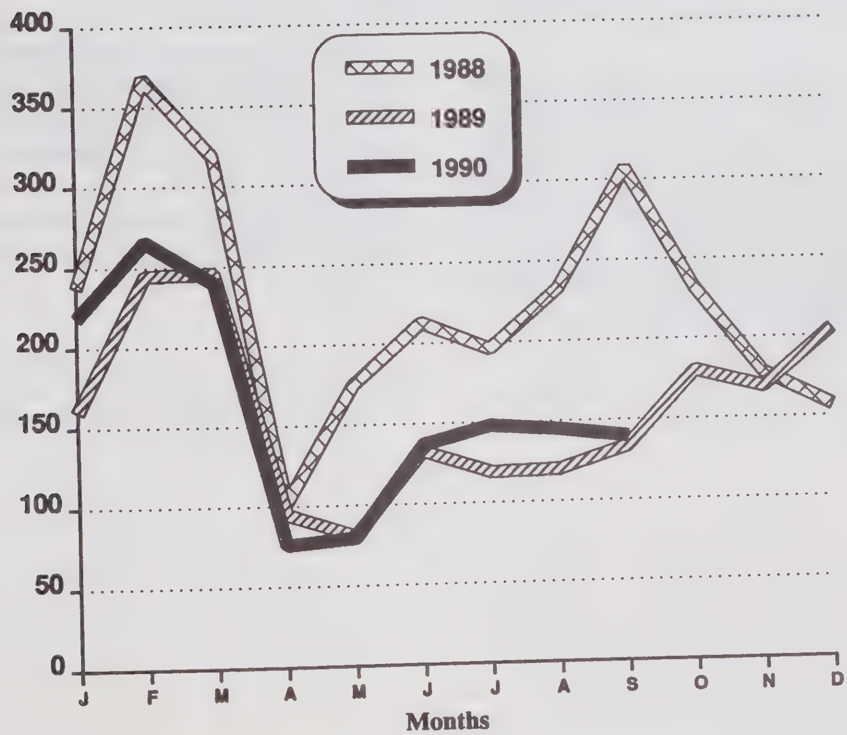


Figure 2.2
Exploratory Well Completions
(January to September)
thousands of wells

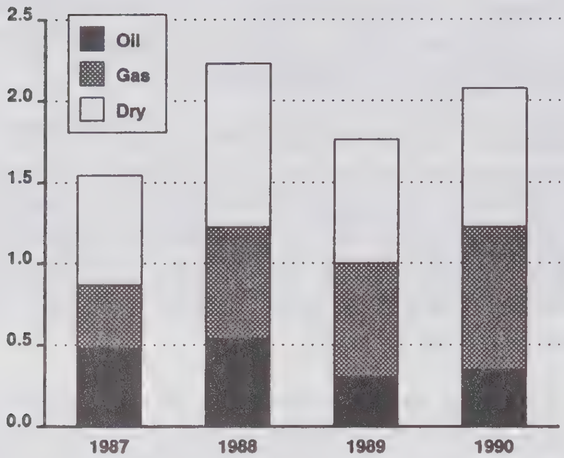
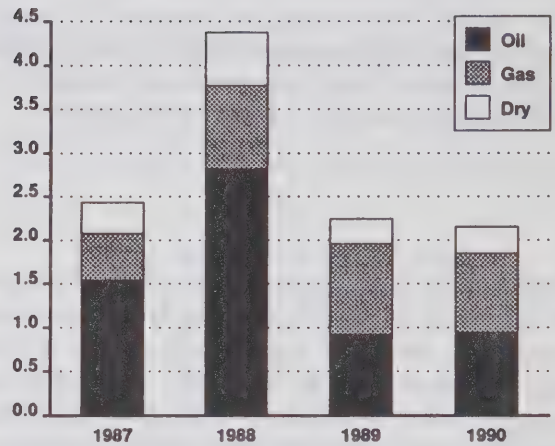


Figure 2.3
Development Well Completions
(January to September)
thousands of wells



There was no apparent incremental increase in drilling, especially for oil, as a result of the Persian Gulf situation. Most producers are said to have found little comfort in the level of oil prices and were in fact not convinced that higher prices would persist over the longer term. As well, expected producer enthusiasm for drilling may have been tempered by past low returns and high industry debt.

Industry analysts predict a modest increase in drilling activity over the next year but caution that producers do not appear ready to launch into a full fledged exploration cycle. However, the Canadian Association of Drilling Contractors (CAODC) suggests that with the upcoming peak winter drilling season coupled with increased cash flows as a result of higher oil prices drilling activity could exceed earlier fourth-quarter expectations.

Over the fourth quarter of 1990 the CAODC forecasts an average of 196 to 205 of an available 480 rigs operating, slightly higher than that forecasted earlier in the year. This would imply a 1990 annual rig utilization rate of about 34 to 35%, nearly five percentage points higher than that recorded in 1989.

For 1991, based on a US$21/bbl (WTI) price, the CAODC forecasts an annual drilling rig utilization rate of about 38%. This would represent a 5% increase in drilling activity over the 1990 annual estimate. The association pegs the first-quarter rate at 56%, 270 of an available 480 rigs operating, compared with a 49% rate recorded during the first quarter of 1990.

3. Crude Oil Supply

- *Domestic crude oil production, crude oil imports and source of imports during the third quarter of 1990 appear to have been little affected by the Persian Gulf conflict.*
- *Domestic production of crude oil increased as refineries on both sides of the border returned to operation following scheduled spring maintenance programs.*
- *Significantly higher foreign crude deliveries were recorded in Quebec and the Atlantic while in Ontario there was a sharp decline in imports from last year.*

3.1 Total Crude Oil Supply

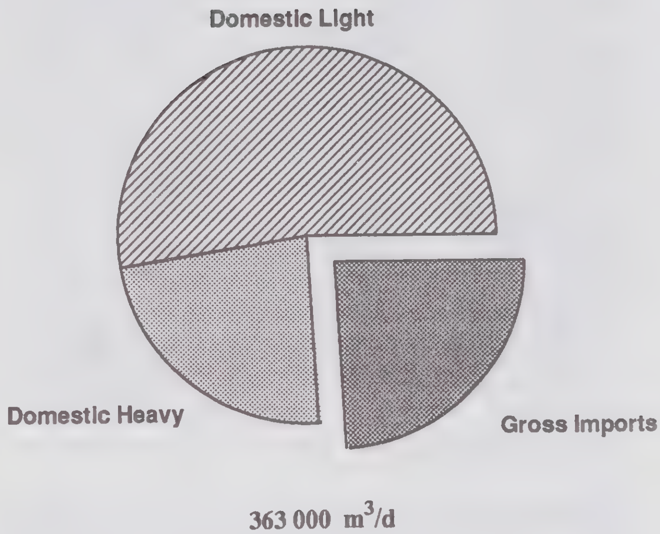
Total supply of crude oil and equivalent during the third quarter of 1990, including gross crude oil imports, averaged 363 000 m^3/d. Higher domestic and export demand pushed supply above the level recorded during the previous quarter (334 000 m^3/d) as well as the third quarter of last year (345 000 m^3/d).

Domestic crude oil supply, characterized by a gradual decline in conventional light crude since late 1988, averaged 276 000 m^3/d. However, during the third quarter conventional light crude production increased above the previous quarter.

Gross crude oil imports also increased. Offshore crudes, accounting for the remainder of supply requirements, were readily available despite of the Persian Gulf situation.

The equivalent of 105 000 m^3/d or almost 30% of total available supply was delivered to the export market.

Figure 3.1
Total Supply of Crude Oil and Equivalent *
(Third Quarter 1990)
000 m^3/d

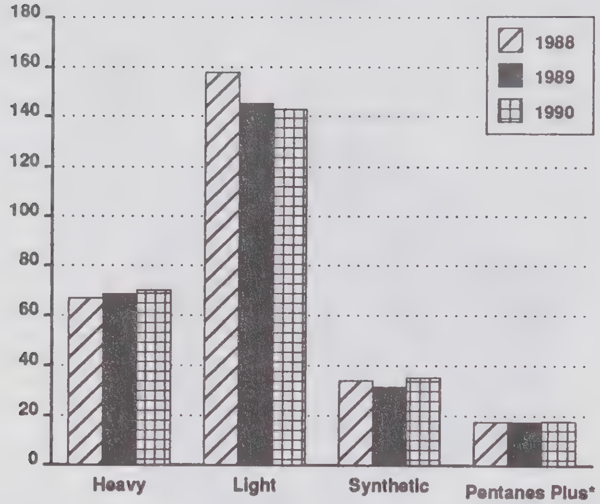


**including production from Ontario, inventory change, recycled diluent and surplus NewGrade supply re-injected into the Interprovincial Pipe Line system as light crude*

3.2 Domestic Crude Oil Supply

Total domestic production of crude oil and equivalent during the third quarter of 1990 averaged 265 000 m^3/d. Although lower than the year before, production increased 4% above the second quarter level. Most of this increase was the result of a significant recovery in light and equivalent crude oil production. However, production lagged well behind that recorded during the same period in 1988 when domestic production approached the highest annual level in a decade.

Figure 3.2.1
Crude Oil Production
(Third Quarter)
000 m^3/d



** Includes condensate*

Higher refinery demand for light and equivalent crudes reflected to a large extent the completion of seasonal refinery turnarounds and the return to full production at the Suncor oil sands plant, this following a late spring turnaround. These factors helped to boost third-quarter production to 195 000 m^3/d, 4% above the previous quarter. Production remained just above the year before.

Conventional light crude oil production, on the decline since late 1988, as a result of a steady depletion of conventional fields, averaged 143 000 m^3/d. Althought third-quarter production was below that recorded a year earlier, production increased 5% over the the second quarter. Most of this increase was recorded in Alberta were production averaged 118 000 m^3/d and returned to about the same level recorded during the first couple months of the year. All other producing regions collectively recorded a marginal increase.

Synthetic crude produced by upgrading oil sands bitumen recorded a 12% gain to 35 000 m^3/d compared to the third quarter of last year. Most of this increase can be attributed to lower than expected output last year as a result of a turnaround at the Syncrude oil sands plant exacerbated by a labour dispute. Compared with the second quarter, production increased by only 3%.

In July synthetic crude production at the Syncrude plant approached a record 30 000 m^3/d, this after an explosion and fire late last year which crippled plant output. Output at the Suncor plant returned to about 10 000 m^3/d after being completely shut down in June for maintenance.

The supply of pentanes plus and condensate during the third quarter, co-products of natural gas production, averaged 17 000 m^3/d, unchanged from a year earlier. About 7 000 m^3/d of this volume was delivered as refinery feedstock with the remainder used as heavy crude oil diluent.

Heavy crude oil and bitumen (unblended) production at 70 000 m^3/d, increased 4% over the previous quarter and 2% above the third quarter of last year. Most of the increase occurred in conventional heavy production (48 000 m^3/d) particularly from southern Alberta as a result of improved enhanced recovery techniques. Bitumen production increased marginally to 22 000 m^3/d.

Based on recent National Energy Board (NEB) estimates, 1990 production is expected to average 262 000 m^3/d, about 4 000 m^3/d below last year's annual average. Although there are some indications of increased exploratory and development activity, the NEB does not expect total supply to increase significantly during 1991.

Supply of conventional light crude oil, reflecting an increase in drilling activity, is expected to continue to decline but at a slower rate than that recorded during 1990. Synthetic production from Suncor and Syncrude oil sands plants, subject to unexpected plant disruptions, is expected to approach capacity. Conventional heavy crude and bitumen production is also expected to register some improvement.

A perceived improvement in crude oil prices and markets for crude bitumen primarily in the United States have prompted ESSO Resources Canada Ltd to cautiously resume expansion of its Cold Lake heavy oil project in northeastern Alberta.

3.3 Crude Oil Imports

Crude oil imports in the third quarter of 1990 rose by 12 000 m^3/d from the previous quarter to exceed 87 000 m^3/d. Virtually all the increase occurred in Quebec. In the second quarter, Quebec refiners had reduced their demand for crude oil to implement scheduled turnarounds. Imports bore the full brunt of this reduction, as the region actually increased its receipts of domestic crude oil during this period. It would appear that Quebec refiners took the opportunity to increase their domestic receipts when demand for domestic crude oil was slackening in Ontario and the Prairies, where some major turnarounds were also being undertaken. However, with seasonal turnarounds for the most part completed by the close of the second quarter, the situation quickly reversed itself in the third, with domestic crude oil availability tightening up as a result of a resurgence in crude oil demand by refineries west of Quebec. Quebec refineries responded by increasing their call on foreign crudes.

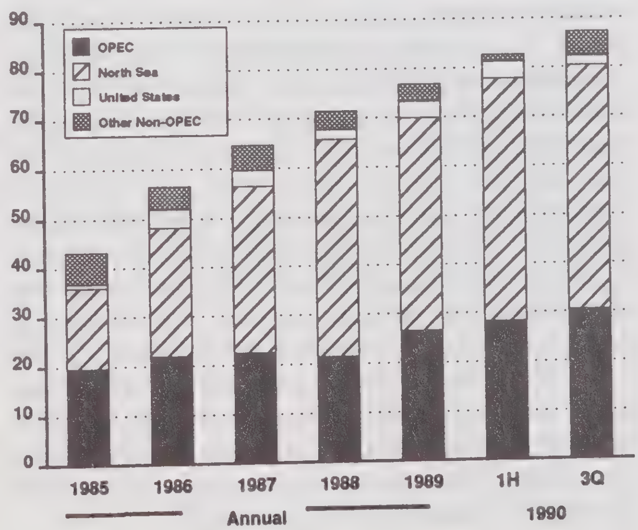
In comparison to the third quarter of last year, total imports were up by 7 000 m^3/d. Higher imports into the Atlantic and Quebec were partly offset by a decline in Ontario. Atlantic refiners increased their foreign crude receipts by almost 3 000 m^3/d to 48 000 m^3/d. Almost 55% of Atlantic imports were acquired from OPEC producers. North Sea crudes accounted for most of the remainder. With refined product consumption remaining virtually flat in the region, the rise in imports stemmed mainly from processing arrangements, whereby imported crude oil is refined by certain Atlantic refiners for the export market. These processing arrangements accounted for roughly 30% of total Atlantic imports during the quarter.

In Quebec, crude oil imports rose by about 10 000 m^3/d year-over-year, averaging 37 000 m^3/d. In part, this rather substantial increase reflected the completion of a capacity expansion at one of region's refineries earlier in the year. This in turn has led to a noticeable reduction in the volume of imports of refined products, notably of motor gasoline and diesel fuel; as well as to a marked rise in oil product transfers to Ontario. Quebec imports were also boosted by a reversal taken in the direction of adjustment of crude oil inventories this year relative to last. During the third quarter of 1989, crude oil stocks in Quebec were drawn down at a rate of 2 500 m^3/d. This year they were built at a rate of almost 1 500 m^3/d. Slightly over 80% of Quebec imports were supplied from the North Sea. OPEC and Mexico supplied the rest.

Imports into Ontario dropped by 6 000 m^3/d year-over-year to a little over 2 000 m^3/d. As usual, U.S. crudes comprised virtually all of the region's imports. The decline related to several events that unfolded either this year or last. In the summer of 1989, Ontario refiners imported light crude oil to help offset a significant shortfall in synthetic crude oil supply that resulted from a prolonged turnaround at Syncrude. The availability of domestic light crude oil was further reduced, and imports boosted when the Newgrade upgrader near Regina was forced to shut down completely causing Ontario-bound domestic light crude oil to be diverted to the refinery adjacent to the upgrader. This summer, by contrast, not only were the synthetic crude and Newgrade operations running at close to capacity but light crude oil demand in the Prairies dropped sharply in the wake of major, unscheduled turnarounds at two Edmonton refineries, all of which helped raise the supply of domestic light crude oil, and concomitantly lower imports in the Ontario market.

As suggested in figure 3.3.1, the conflict in the Persian Gulf, which erupted at the beginning of August, seems to have had little effect on either the level or origin of crude oil imports into Canada during the third quarter.

Figure 3.3.1
Imports of Crude Oil by Source
000 m^3/d



4. Crude Oil Disposition

- *The Persian Gulf conflict appears to have had little impact on crude oil deliveries to Canadian refineries during the third quarter.*

- *Most of the increase in crude oil receipts this year occurred in the Atlantic and Quebec, as a result of more refining activity in these regions.*

- *Exports during the third quarter at 105 000 m^3/d, were 5% above a year earlier.*

4.1 Canadian Refinery Crude Oil Receipts

After falling to their lowest quarterly level in two years during the second quarter of 1990, crude oil deliveries to Canadian refiners rebounded during the third quarter, rising 30 000 m^3/d to average about 259 000 m^3/d. In comparison to the same quarter last year, refinery receipts were up by 15 000 m^3/d. This higher year-over-year crude oil demand resulted from a 12 000 m^3/d increase in crude runs, in part to meet higher refined product demand; combined with a smaller drawdown of crude oil inventories this year relative to last.

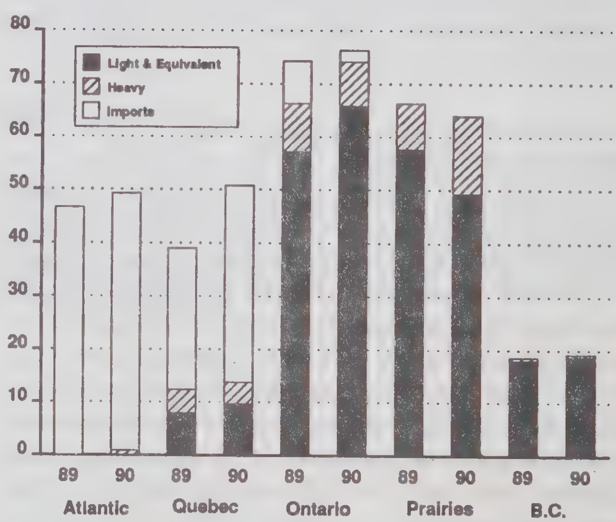
It is interesting to note that the conflict in the Persian Gulf does not appear to have had any major repercussions, at least in volumetric terms, on crude oil deliveries to Canadian refineries. Actual deliveries during the quarter corresponded quite closely to those originally intended, judging from a survey of refiners' crude oil nominations completed by the NEB in early July. If anything, the conflict appears to have increased receipts of domestic crude oil slightly, while reducing the volume of imports.

Demand for domestic crude oil rose by 8 000 m^3/d from last year to nearly 172 000 m^3/d, with almost three quarters of the increase attributable to higher heavy crude oil receipts at the Newgrade upgrader. After undergoing a scheduled turnaround which lasted the whole of June, the 8 000 m^3/d upgrader managed to operate at near capacity throughout the third quarter. Receipts of domestic light crude oil, on the other hand, were sustained by a substantial gain in synthetic crude output, which raised the general availability of light crude oil.

Nevertheless, foreign crude deliveries also rose, by 7 000 m^3/d to 87 000 m^3/d, highlighting the fact that on a regional basis, the overall increase in crude oil receipts was, by and large, concentrated in the predominantly import-dependent Atlantic and Quebec regions. Atlantic receipts rose 3 000 m^3/d to approach 49 000 m^3/d. This increase reflected Atlantic refinery processing agreements rather than regional product demand. Although some domestic heavy crude oil was transhipped to Atlantic refiners in September, most of the increase in the region's receipts consisted of imports.

Foreign crudes also accounted for almost 90% of the 12 000 m^3/d rise in deliveries to Quebec refiners. Averaging 51 000 m^3/d, Quebec receipts were at their highest level since the early 1980's. The rise in Quebec crude oil demand resulted from a combination of factors including: a significant expansion in capacity at one of Quebec's refineries which has meant fewer refined product imports (in particular of transportation fuels), a rise in product transfers to the Ontario market and a significant build of crude oil inventories during the quarter vis-a-vis an even larger drawdown last year.

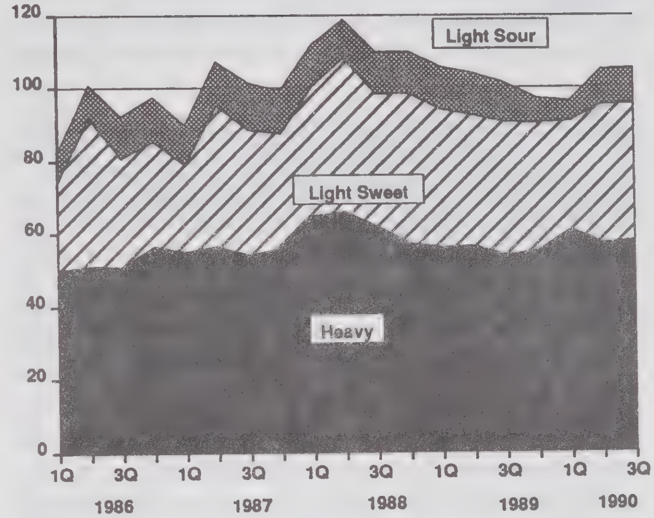
Figure 4.1
Crude Oil and Equivalent Refinery Receipts by Region
(Third Quarter)
000 m^3/d



Foreign crude receipts might have been higher still were it not for the 6 000 m^3/d drop in imports into Ontario this year. Ontario refiners more than compensated for this deficit by increasing their call on domestic light crudes by 8 000 m^3/d. The latter was facilitated by unscheduled turnarounds at two Edmonton refineries which dropped demand for light crude oil in the Prairies by a similar amount. In total, crude oil deliveries to Ontario rose by 2 000 m^3/d to 76 000 m^3/d.

In western Canada, the problem-free operation of the NewGrade upgrader kept refinery receipts in the Prairies from falling further than they otherwise would have because of the aforementioned turnarounds. Prairie demand fell by only 3 000 m^3/d overall, to 63 000 m^3/d. Crude oil receipts in British Columbia, on the other hand, increased marginally from last year to 19 000 m^3/d.

Figure 4.2.1
Crude Oil Exports
000 m^3/d



4.2 Crude Oil Exports

Crude oil exports during the third quarter of 1990 averaged 105 000 m^3/d. While the level remained unchanged from the previous quarter, exports recorded a 5% increase over the third quarter of last year. On a cumulative basis, exports over the first nine months of the year averaged 102 000 m^3/d, marginally lower than the same period a year earlier.

Exports have been on the decline since 1988, for the most part, the result of consistent shortfalls in light conventional crude oil production. However, third-quarter exports were supported by a modest increase in conventional light crude and synthetic supply (as discussed in the previous section) and strong seasonal demand for heavy crude oil by U.S. refiners for asphalt production.

Third-quarter crude oil exports represented about 40% of total domestic crude oil and equivalent production (71% of blended heavy supply and 26% of net light crude production).

Heavy crude oil exports averaged 58 000 m^3/d. Although marginally higher than the previous quarter, exports were 8% above the third quarter of 1989. Total light crude exports held at about 47 000 m^3/d with increased shipments of synthetic crude compensating, to a certain extent, for a decline in conventional light crude deliveries. Light sweet exports averaged 38 000 m^3/d.

As illustrated in Appendix IV most Canadian crude and equivalent exports are delivered to the United States. Three-quarters of these exports are typically delivered to U.S. PAD District II (the Twin Cities and Chicago refining areas).

Deliveries to PAD District II during the third quarter totaled 81 000 m^3/d, slightly higher than the previous quarter but 6% above the volume shipped a year earlier. Sales of heavy crude to the district increased by 6% to 53 000 m^3/d. Light crude exports, although down somewhat from the previous quarter, increased by nearly 6% to 28 000 m^3/d when compared with a year earlier.

Third-quarter exports to Canada's second largest market, PAD District IV (the Montana and Wyoming refining areas), held at about 14 000 m^3/d. All other PAD Districts recorded minor adjustments. No offshore deliveries were recorded.

Export demand for crude oil and equivalent is expected to remain strong but affected by a number of factors; in particular, the economic slowdown on both sides of the border and the uncertainty generated by the Middle East situation.

5. Pipelines

- *Total deliveries on the two main trunk lines were up during the third quarter compared to the same period last year.*

Western Canadian crude oil is, for the most part, delivered to markets through a network of pipelines. A map illustrating major crude oil pipelines in North America is shown below.

The Trans Mountain Pipe Line and the Interprovincial Pipe Line originate in Edmonton, where most Canadian crude oil is gathered. The Rangeland pipeline supplies U.S. refiners south of the Prairie provinces. The selected American pipelines shown on the map illustrate the supply alternatives for our main export market. Chicago can be supplied with U.S. domestic crudes from Cushing, Oklahoma, with foreign crudes from the U.S. Gulf (LOOP), and with Canadian crudes via the Interprovincial Pipe Line.

5.1 Trans Mountain Pipe Line

During the third quarter of 1990, Trans Mountain Pipe Line (TMPL) throughput averaged 26 000 m^3/d, virtually unchanged from the previous quarter and 5% above the same period last year. (See Appendix V)

Total deliveries of crude oil to refineries in British Columbia during the third quarter averaged 16 000 m^3/d, approximately 1 000 m^3/d higher than the second quarter. Deliveries were up by 1 000 m^3/d compared to the same period of 1989. Deliveries of semi-refined products increased slightly by 500 m^3/d over the previous third quarter to 6 000 m^3/d. Deliveries of refined products from Edmonton to Kamloops, British Columbia remained stable at 3 000 m^3/d.

Overall, total domestic deliveries increased by 2 000 m^3/d or 6% over the second quarter and by 1 000 m^3/d or 5% on a period-over-period basis.

Crude oil deliveries for export by tanker at the Westridge Marine Terminal averaged 1 000 m^3/d, almost 500 m^3/d less than a year ago.

Pipeline exports from Sumas to the Puget Sound area averaged 1 000 m^3/d during the quarter representing a decrease of 1 000 m^3/d from last year.

Figure 5.
Major Crude Oil Pipelines In North America

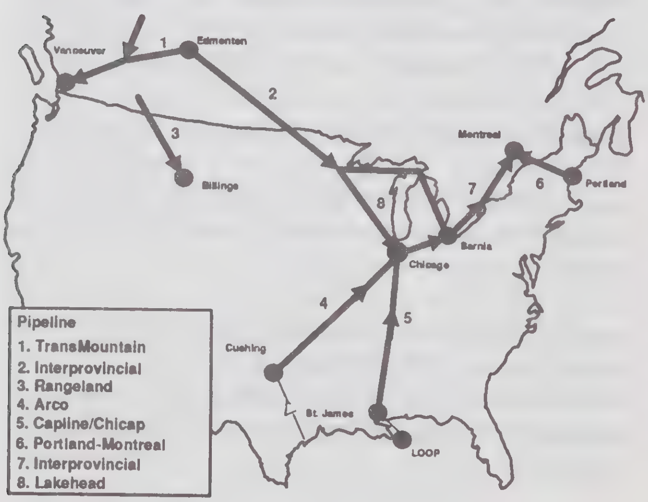
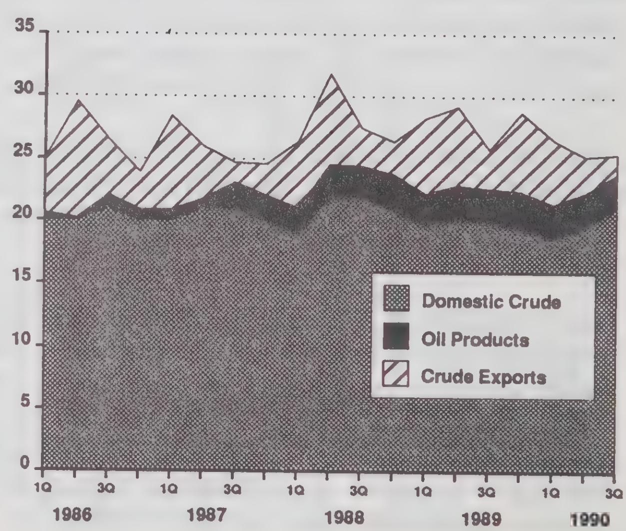


Figure 5.1
Trans Mountain Deliveries
000 m^3/d



5.2 Interprovincial Pipe Line

The Interprovincial Pipe Line system consists of two connected segments, the first one is in Canada and is commonly referred to as IPL while the second, called 'Lakehead', serves American markets in the Great Lakes area.

Total IPL and Lakehead deliveries of crude oil and other hydrocarbons, including petroleum products and natural gas liquids, during the third quarter of 1990, averaged 226 000 m^3/d, up approximately 4 000 m^3/d from the previous quarter and 3 000 m^3/d from one year ago.

Total deliveries of crude oil to Canadian refineries during the third quarter were 130 000 m^3/d, 2 000 m^3/d (2%) less than a year earlier and 5 000 m^3/d higher than the second quarter. Deliveries to Canadian refiners represented 57% of IPL total throughput. Deliveries to the United States, at 96 000 m^3/d, were up 5 000 m^3/d (5%) from the same quarter the previous year.

5.3 Pipelines to Montreal

Total deliveries of crude oil and equivalent to Montreal refiners, during the third quarter of 1990, averaged about 32 000 m^3/d, up 3 000 m^3/d from the same quarter a year earlier.

Total domestic crude deliveries via the Sarnia-Montreal portion of the IPL system averaged 15 000 m^3/d, 1 000 m^3/d more than the year before. About 14 000 m^3/d were for use by Montreal refineries with the remainder exported or transfered to refineries in the Atlantic region. Foreign crudes, imported mainly through the Portland Pipe Line, averaged 18 000 m^3/d, up 2 000 m^3/d from the same period last year.

Figure 5.2
Total IPL Deliveries
000 m^3/d

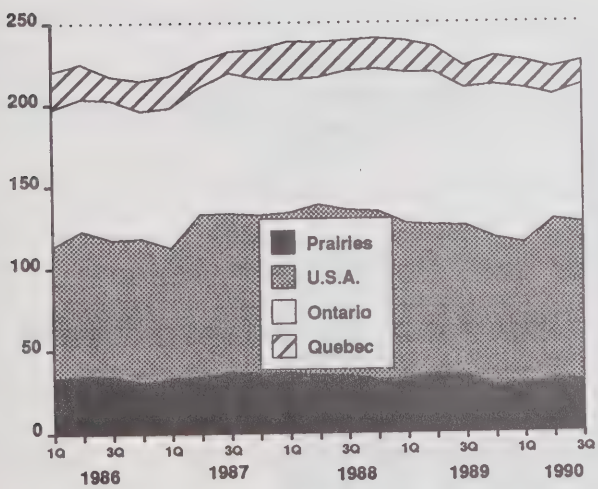
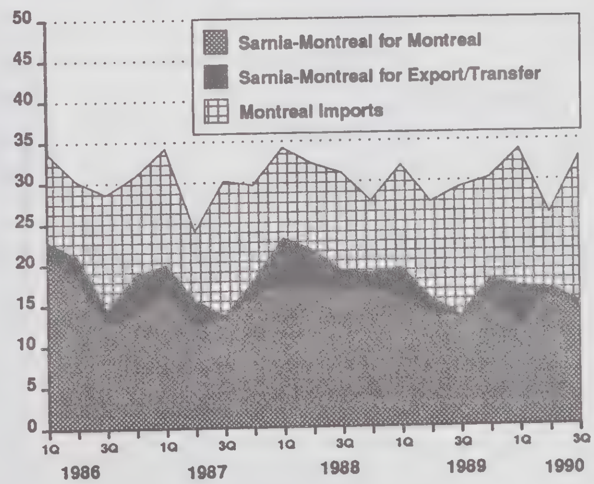


Figure 5.3
Deliveries to Montreal
000 m^3/d



6. Refinery Throughput and Utilization Rates

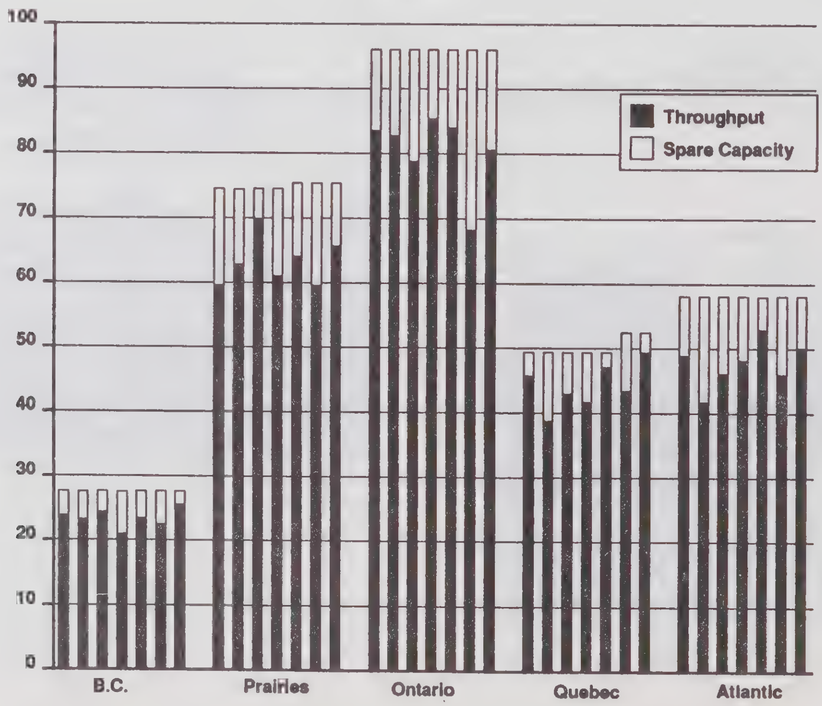
- *After falling to a two year low during the second quarter because of a large number of refinery turn-arounds, the national refinery utilization rate recovered in the third, rising 10 percentage points to 88%.*

- *Quebec refineries continued to record the highest rate of utilization, and those in Ontario the lowest.*

Refinery throughput will normally diverge from refinery crude oil receipts for two reasons. First, feedstocks other than crude oil are also charged in the refining process. Some of the 'other' feedstocks include gas plant butanes (used mostly by Prairie refineries) and partially processed oil (used mostly by refineries in British Columbia). During the third quarter, these 'other' receipts averaged 12 000 m^3/d or about 4% of total refinery throughput in Canada. Second, refinery throughput reflects changes in feedstock inventories. Other things being equal, an inventory drawdown will cause refinery throughput to exceed receipts - and vice versa in the case of an inventory build. During the third quarter, crude oil inventories at the national level were drawndown at a rate of less than 1 000 m^3/d.

During the third quarter, total throughput averaged 272 000 m^3/d, about 10 000 m^3/d higher than during the corresponding period in 1989. With estimated Canadian refining capacity now up by about 4 000 m^3/d to almost 310 000 m^3/d, (due to capacity expansions earlier in the year at refineries in Quebec and the Prairies), this level of throughput corresponded to a national refinery utilization rate of about 88% on a calendar day basis. The utilization rate was highest in Quebec where it reached 95%, and lowest in Ontario, at 84%. The figure below illustrates refinery throughputs and capacities by region, starting from the first quarter of 1989.

Figure 6.1
Refinery Utilization vs Capacity
(1st Quarter 1989 to 3rd Quarter 1990)
000 m^3/d



7. Stocks

- *Stocks of crude oil and refined petroleum products declined by 12% since the first quarter of 1990*
- *Stock build which normally occurs in the third quarter failed to materialize as a result of a significant draw-down of product inventories.*

Stocks of crude oil and petroleum products have been on the decline since the first quarter of the year. Closing September 1990 stocks (based on preliminary Statistics Canada data) totalled 13.9 million m^3, down 3% from the second quarter and 6% below the third quarter of 1989.

Product stocks during the third quarter, representing about 80% of total inventories, dropped to 11.1 million m^3, down almost 10% from the previous year. However, crude oil stocks at 2.8 million m^3 recorded a 9% increase, the result of a significant draw in Quebec last year due to a tight domestic light crude oil supply situation during that period.

Stocks fell across all regions with most of the third quarter year-over-year drop recorded in Ontario and the Prairies. However, when compared with the second quarter of the year, all of the stock drop occurred in western Canada where product inventories fell 14%. Most of this drop is attributed to unscheduled refinery turnarounds.

Stocks of 'main' petroleum products at 7.6 million m^3 dropped 13% from the third quarter of last year. While all 'main' products declined, middle distillate recorded the largest drop followed by motor gasoline. The 'other' products category which includes such items as jet fuels, petrochemical feedstocks and asphalt, remained relatively unchanged.

By the end of September the ratio of total stocks to consumption represented about 58 days of supply, down from 64 days the year before. If the Atlantic region is excluded from the calculation of the third quarter ratio, because a large portion of Atlantic shipments are directed to export markets and the region is not 'pipeline-connected' to domestic supplies, the ratio for Canada would have been about 53 days.

Stocks referred to do not include estimates of crude oil held in pipeline tankage. If these stocks were included, it is estimated that the ratio of total stocks to consumption would increase by about 7 days to 65 days.

Table 7.1
Closing Crude and Product Inventories*
(End September)
000 m^3

	Crude			Product		
	1988	1989	1990	1988	1989	1990
Atlantic	1236	1102	1169	1935	1952	1785
Quebec	718	542	699	2559	2781	2444
Ontario	504	612	581	3811	3771	3442
Prairies	184	243	282	2494	2577	2225
B.C.	100	79	76	1190	1156	1159
Canada	2742	2578	2807	11989	12237	11055

Table 7.2
Ratio of Stocks to Consumption*
(End September)
days

	Crude			Product		
	1988	1989	1990	1988	1989	1990
Atlantic	45	39	34	70	69	51
Quebec	14	11	13	51	55	45
Ontario	7	8	8	50	47	45
Prairies	4	5	6	51	54	44
B.C.	4	3	3	45	46	43
Canada	12	11	12	52	53	46

* *Note: 1990 stock numbers are preliminary*

Table 7.3
Petroleum Product Inventories*
(End September)
000 m^3

	1988	1989	1990
Main Products:	8544	8655	7554
Motor Gasoline	3576	3774	3342
Heating Oil	1654	1633	1338
Diesel Fuel	2287	2306	2028
Heavy Fuel	938	942	846
Other	3534	3582	3501
Total	**11989**	**12237**	**11055**

8. Crude Oil and Product Prices

- *International and domestic crude oil and petroleum product prices began to increase over the third quarter in response to the Persian Gulf situation.*

8.1 International Crude Oil Prices

At the beginning of the third quarter of 1990, crude oil prices were relatively soft, with the price of West Texas Intermediate (WTI) below US$17/bbl. This weakness in price was primarily due to an oversupplied market as several OPEC members were producing above their quotas. Prices did, however, begin to rise as the July 26, 1990 OPEC Ministerial meeting approached. The meeting ended with an agreement by all members to increase the crude oil production quota to 22.5 MMB/D. The UAE's quota was increased from 1.1 MMB/D, to 1.5 MMB/D (the UAE had been producing about 2 MMB/D, almost 1 MMB/D above its quota). OPEC also agreed to raise its crude oil reference price from US$18 to $21/bbl.

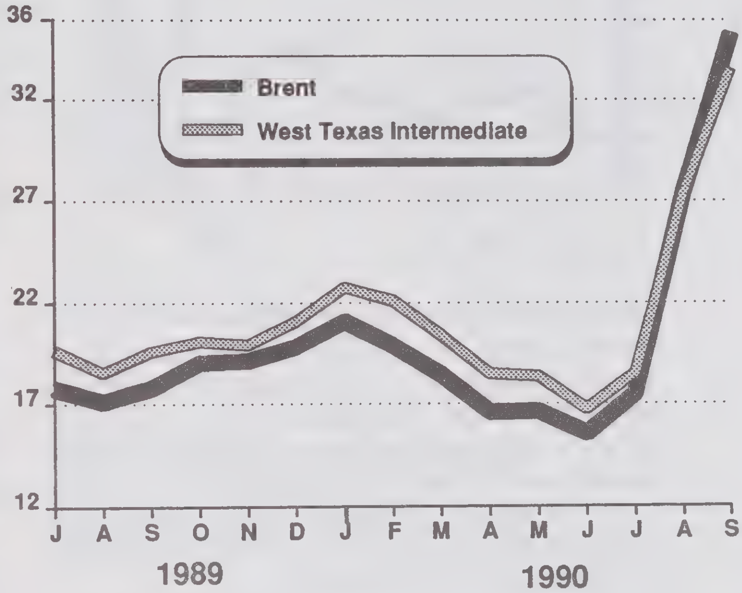
Crude prices rose dramatically following the August 2 Iraqi invasion of Kuwait. The subsequent decision by the U.N. Security Council to embargo Iraqi and Kuwaiti oil resulted in a loss of 4.1 MMB/D of crude oil to the market. To offset this shortfall and stabilize the oil market, OPEC members held an emergency meeting in August, where they agreed to temporarily abandon production restraints, thereby allowing members to increase oil output to maximum productive capacity.

Crude oil prices remained extremely volatile over August and September, despite higher OPEC and non-OPEC output. Prices were vulnerable to the speculative nature of the oil market, responding to political and military reports emanating from the Gulf rather than to supply/demand fundamentals. By the end of September, the price of WTI had reached US$38/bbl, its highest level since late 1981.

Over the third quarter, WTI averaged US$25.90/bbl, up from its first and second quarter averages of US$21.90/bbl and $18.05/bbl, respectively and from the third quarter of 1989 when WTI averaged US$19.30/bbl.

Figure 8.1 illustrates monthly Brent and WTI prices. As indicated in the graph, prices moved steadily upwards throughout the quarter.

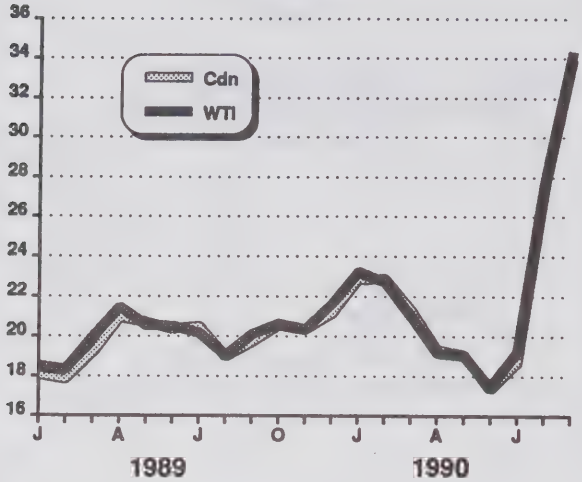
Figure 8.1
International Crude Oil Prices
US$/bbl.



8.2 Domestic Crude Oil Prices

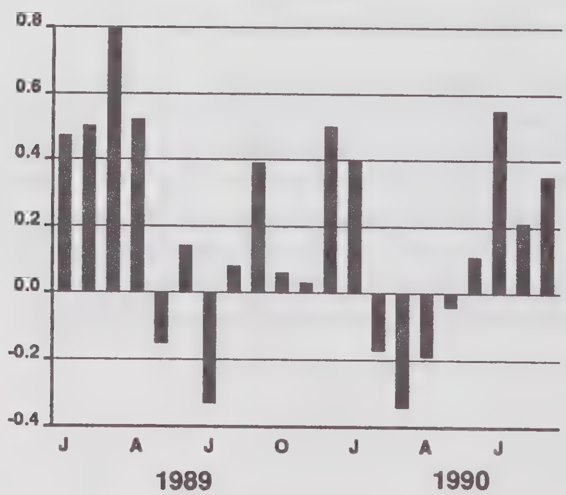
During the third quarter of 1990, the posted price of Canadian Par crude oil (the Canadian benchmark crude at 40°API, 0.5% S) averaged $29.22/bbl, an increase of $8.93/bbl over the second quarter of 1990. The increase can be attributed to a combination of an international oil price increase (about $8.50/bbl), a strengthening of the Canada/U.S. exchange rate and an increase of the differential between Canadian and international prices.

Figure 8.2.1
Canadian Par Crude vs WTI (NYMEX*) at CHICAGO
US$/bbl



The differential between Canadian Par and WTI NYMEX prices, on a calendar basis in Chicago, is illustrated in figure 8.2.2. The average differential in the third quarter was US$0.37/bbl in favour of WTI NYMEX, compared to an average of US$0.04/bbl for the second quarter in favour of Canadian Par. The increase in the differential reflects a move to a calendar month average of WTI prices as the benchmark for Canadian crude oil prices in the third quarter.

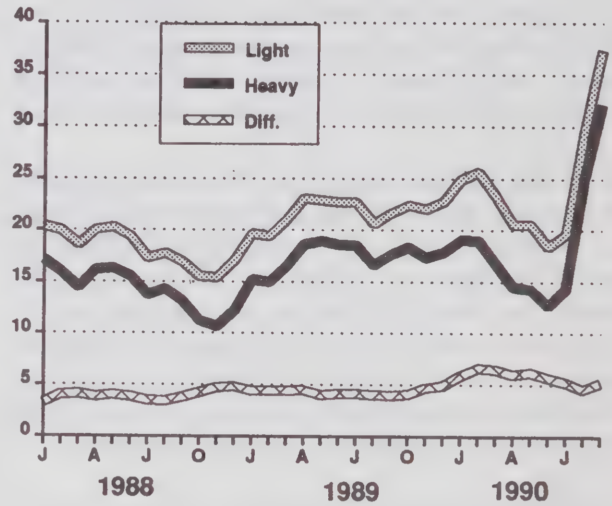
Figure 8.2.2
Canadian Par vs WTI (NYMEX*)
(Differential at Chicago)
US$/bbl



** New York Mercantile Exchange*

Figure 8.2.3 compares actual prices for Alberta light and heavy crude oil, purchased for use in Canada at the main trunk line injection stations. On average, reported light conventional crude oil quality during the third quarter of 1990 was 37.6° API, 0.40% sulphur and blends of heavy crude were 24.2° API, 2.48% sulphur. The differential between Canadian light and heavy crude oil prices during the third quarter of 1990 was $5.04/bbl, $0.96/bbl lower than the second quarter differential, reflecting the short-term seasonal change in demand for heavy crude oil.

Figure 8.2.3
Comparison of Domestic Light and Heavy Crude
(Actual Purchase Price- Alberta)
CAN$/bbl



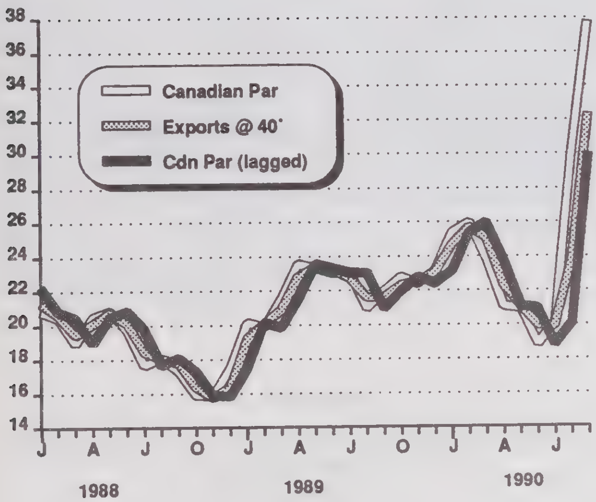
8.3 Export Prices

Figures 8.3.1 and 8.3.2 illustrate the relationship between light crude oil export prices and domestic prices.

Prices of light crude oil exported to the United States via the IPL system were netted back to Edmonton and adjusted to 40°API, on a stream by stream basis. These prices were then compared to Canadian Par crude prices, also at Edmonton.

As can be observed in figure 8.3.1, in a period of declining prices, exports would appear to be more expensive than Par crude for the same month; and, in a period of increasing prices, exports would appear to be cheaper. An evaluation on that basis alone would be misleading. Canadian Par crude prices were therefore "lagged" one month to normalize for differing delivery times of export crude.

Figure 8.3.1
Exports vs Canadian Par
CAN$/bbl

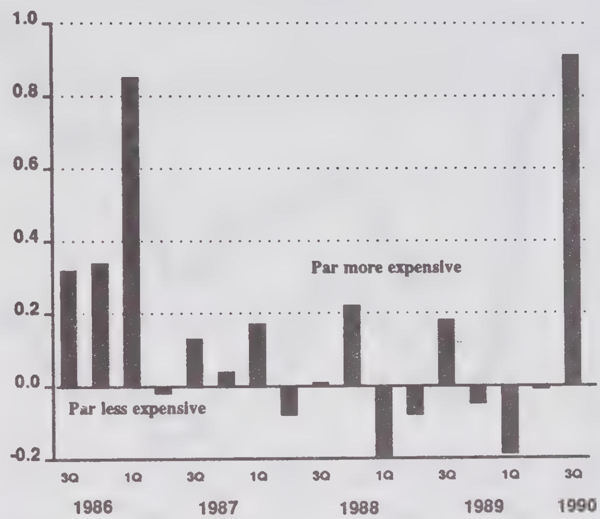


For comparison purposes, an average of the current month's Par crude and it's lagged price was calculated. Figure 8.3.2 illustrates the differential between this composite average Par crude and the average export price.

During the third quarter, export prices continued to track the range established by Canadian Par crude prices.

In figure 8.3.2 the apparent discount of export prices observed in the third quarter, of $0.91/bbl, results from a combination of the rapidly increasing prices following Iraq's invasion of Kuwait and an increase in the availability of light crude supply to both the domestic and export markets.

Figure 8.3.2
Exports vs Canadian Par
Price Differential
CAN$/bbl



8.4 Petroleum Product Prices

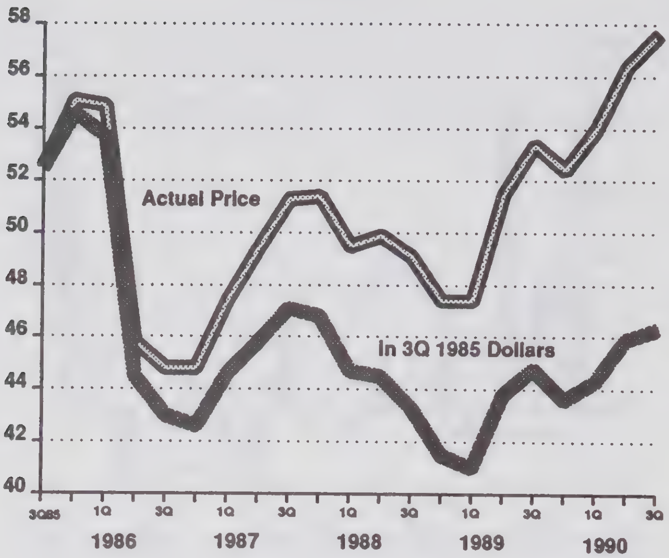
Price Trends

Gasoline and Diesel

During the third quarter of 1990, the price of regular unleaded gasoline averaged 57.6 cents per litre, an increase of 1.2 cents per litre over the second quarter average. (Figure 8.4.1) Although the third quarter 1990 price is 5.1 cents per litre above the third quarter 1985 price, when the pump price, including tax, is adjusted for inflation the average price has declined 6 cents per litre or 12% over the period.

Towards the end of the third quarter of 1990, gasoline and diesel prices began to increase across Canada. These price increases were in response to crude oil price increases which occurred in mid-July as well as from higher crude costs which resulted from Iraq's invasion of Kuwait.

Figure 8.4.1
Regular Unleaded Gasoline Prices
(10 City Average)
cents/litre



While Canadian crude costs increased almost 17¢/litre during the third quarter (September 25 vs June 26), 14 cents of the increase occurred after the invasion. Although regular unleaded gasoline prices increased only an average 4 cents per litre, or 7%, during the third quarter (See Appendix VIII), they continued to increase into the fourth quarter. In mid-November, the average Canadian regular unleaded gasoline price reached a high for the year of 67.1 cents per litre, 10 cents per litre above the pre-invasion price.

The price of gasoline increased in nine of the ten cities surveyed over the third quarter. The only decrease was in Halifax where the end-September price was 1.2 cents per litre below the end-June price. Price increases in the other cities ranged from 0.8 cents per litre in Charlottetown to 7 cents per litre in Winnipeg, where a price war ended in July.

Diesel prices also increased during the third quarter, up an average of 2.9 cents per litre. Prices were unchanged in Vancouver and the highest increase, 5 cents per litre, was recorded in Calgary.

Consumption Taxes on Petroleum Products

The quarterly review of federal sales taxes resulted in increases in the gasoline and diesel taxes of 0.11 cents per litre. The excise tax did not change.
(See Appendix IX)

During the third quarter, taxes increased in the Northwest Territories and four provinces, Prince Edward Island, Nova Scotia, New Brunswick and British Columbia. All of the increases were the result of regular reviews.

Canada vs United States

While the situation in the Persian Gulf influenced gasoline prices in Canada, the price increases in the United States occurred faster and were greater than those in Canada. In September 1990, the United States and Canadian prices were 6.1¢/litre and 1.2¢/litre, respectively, above the June 1990 prices. In the United States, higher crude oil prices and refining and marketing costs and profits were responsible for the increase. In Canada, higher refining and marketing costs and profits offset lower crude costs resulting in a slight price increase.

Figure 8.4.2
Average Retail Price of Motor Gasoline
(Canada vs United States)
cents/litre

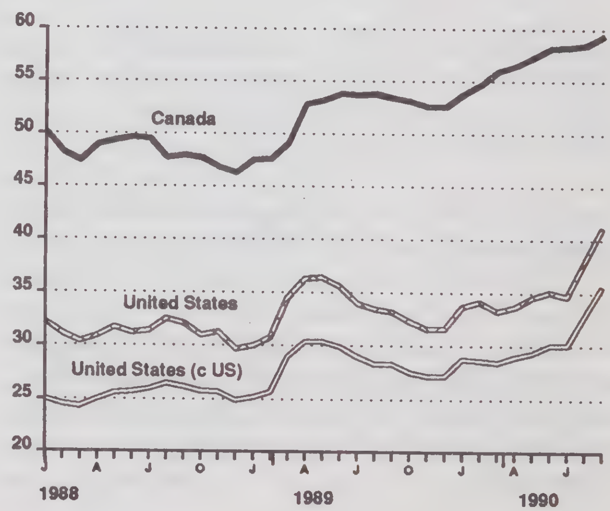
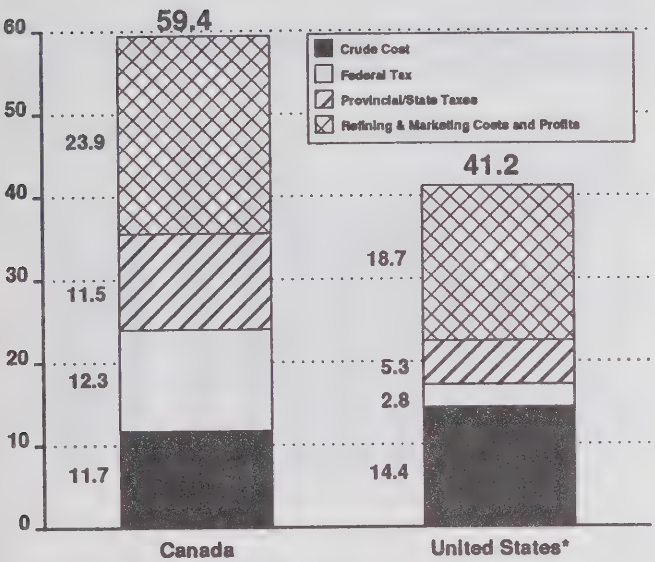


Figure 8.4.3
Breakdown of Average Pump Price
(September 1990)
cents /litre



* *Exchange rate = 1.1582*

Although the price in Canada remains higher than in the United States, the differential between the prices declined for the second consecutive month in September. The differential was 18.2¢/litre, 4.9¢/litre lower than the differential in June. Higher taxes in Canada continue to account for the bulk of the differential, about 85% in September. The balance is attributable to higher refining and marketing costs and/or profits in Canada.

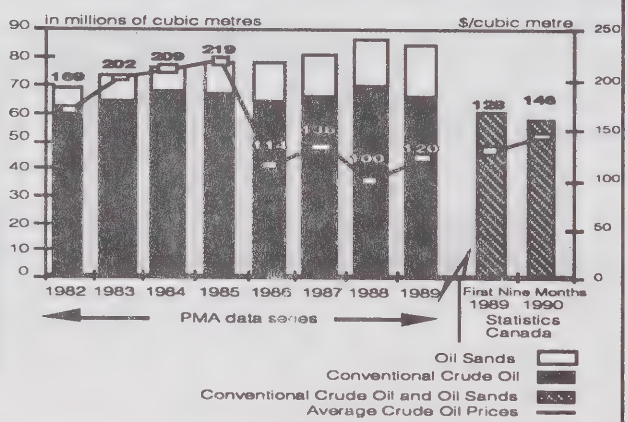
9. Financial Performance of the Canadian Oil and Gas Industry

The following section was prepared by the Petroleum Monitoring Agency (PMA). Further information is available from V. Stanciulescu (613) 995-2100 and F. Laberge 996-8035.

- *Net income after unusual items rose 9% to $1.4 billion in the first nine months of 1990 above levels realized in the first nine months of 1989.*
- *Internal cash flow decreased 5% to $5.4 billion in the first nine months of 1990 from $5.7 billion.*
- *Gross capital expenditures increased 4% to $4.9 billion in the first nine months of 1990 with a rise in the reinvestment rate to 89% from 80% in the corresponding 1989 period.*
- *Dividend payments in the first nine months of 1990 declined 3% to $885 million from $915 million.*

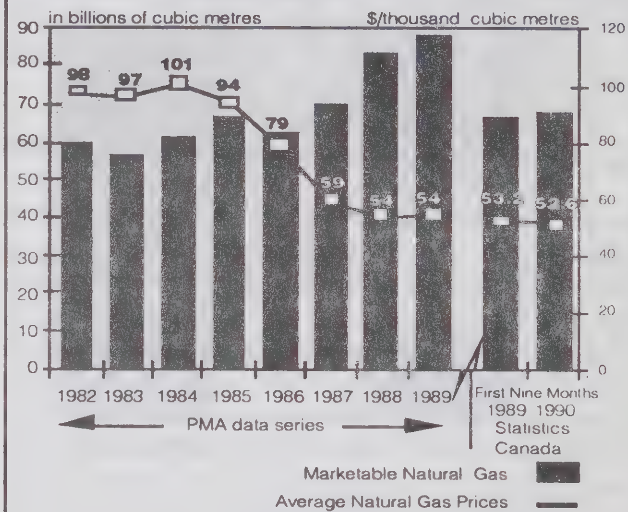
Total sales revenues increased 10% to $32.5 billion in the first nine months of 1990 from $29.6 billion in the corresponding 1989 period. Increased sales revenues resulted primarily from higher crude oil prices which occurred in the third quarter, following supply fears caused by instability in the Persian Gulf. Average crude oil prices rose 14% in the first nine months of 1990; this increase, along with a 1% increase in marketable natural gas production, more than compensated for the decline in crude oil production and natural gas prices.

Figure 9.1 Crude Oil Volumes and Average Prices: 1982 - 1990



In addition, higher revenues from refined petroleum products were due to larger sales volumes and the flow through to consumers of increased feedstock costs and higher federal sales and excise taxes.

Figure 9.2 Marketable Natural Gas Volumes and Average Prices: 1982 - 1990

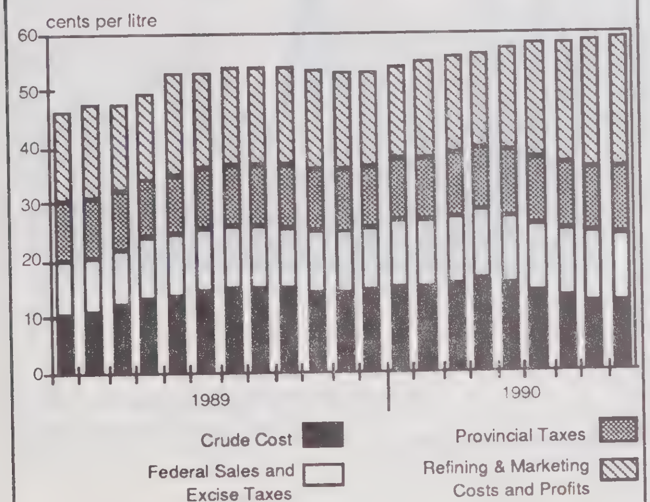


Note: The data for figures 9.1 and 9.2 are taken from the PMA's Monitoring Survey data base except for the two end bars which are derived from Statistics Canada and EMR Oil and Gas Branch. The two data series are **not** entirely comparable since the PMA data shows prices to the producers, while the other data include transportation and gathering costs and are, therefore, higher than PMA numbers. The Monitoring Survey covers approximately 90% of the industry, compared with 100% for the other data series.

Net income from all Canadian operations of the industry rose 9% ($110 million) to $1.4 billion in the first nine months of 1990 over the corresponding 1989 period. The impacts of higher revenues and lower E&D expenses charged to current operations were almost entirely offset by higher 'other expenses', which includes operating and feedstock costs. However, unusually high gains on sale of assets in the first nine months of 1990 resulted in a 27% ($510 million) increase in net income prior to income taxes. However, increased current income taxes of 85% or $475 million, moderated the rise in net earnings. Increased current taxes were, in part, due to deferral of tax liability from 1989 to 1990, following a corporate restructuring (Table 9.7).

Internal cash flow declined 5% ($285 million) to $5.4 billion in the first nine months of 1990. The main factor contributing to this decrease was higher current income taxes of 85% ($475 million). The large gain on sale of assets, while positively affecting net income, does not enter into the cash flow.

Figure 9.3 Average Retail Price of Motor Gasoline: Monthly, 1989 - 1990



Source: EMR, Oil and Gas Branch

Table 9.1 Overview of Total Industry

First Nine Months

	1989	1990	Change	
	---- $ billions ----			(%)
Total Sales Revenue	29.6	32.5	2.9	10
Other Revenues	0.5	0.9	0.4	63
Total Expenses	26.4	29.1	2.7	10
All Current Taxes	0.6	1.0	0.4	85
Deferred Taxes	0.3	0.1	-0.2	-39
Net Income before Extraordinary Items	**1.1**	**1.2**	**0.1**	**15**
Extraordinary and Other Items	0.2	0.2	--	-22
Net Income after Extraordinary Items	**1.3**	**1.4**	**0.1**	**9**
Internal Cash Flow	**5.7**	**5.4**	**-0.3**	**-5**

Canadian-controlled companies' net income dropped 44% ($215 million) to $270 million in the first nine months of 1990. Higher sales revenues of $1.3 billion (13%) were more than offset by the combination of higher 'other expenses' (includes operating and feedstock costs) of $990 million, interest charges of $90 million, DD&A of $180 million, current and deferred income taxes of $105 million.
Cash flow, unaffected by non-cash charges, increased 5% ($110 million) to $2.1 billion in the first nine months of 1990 over the corresponding 1989 period.

Foreign-controlled companies' net income rose 41% ($325 million) to $1.1 billion in the first nine months of 1990 from $785 million in the corresponding 1989 period. The impact of higher sales revenues of 8% ($1.6 billion), and lower E&D charges to current operations and interest expenses, down $160 million and $110 million respectively, was almost offset by increased 'other expenses' of 11% or $1.7 billion and lower dividend and interest revenues. However, a $415 million increase in gains on sale of assets, along with a $55 million gain on currency translation increased net income, despite a $250 million (39%) rise in income taxes.
Internal cash flow, unaffected by gains on sale of assets, declined 11% to $3.3 billion in the first nine months of 1990.

Dividend payments by the petroleum industry decreased 3% to $885 million in the first nine months of 1990 from $915 million in the corresponding 1989 period. Dividends paid by Canadian-controlled companies increased 7% to $325 million, while dividend payments by foreign-controlled companies declined 8% to $555 million.

Table 9.2 Dividend Payments

First Nine Months

	1989	1990	Per Cent of Net Income(a) 1989	1990
	- -$ millions - -		(%)	
Canadian-Controlled	307	327	59	124
Foreign-Controlled	606	557	69	49
Total Industry	913	884	65	63

(a) Percentages are derived by dividing dividend payments by the net income.

Overall gross capital expenditures for the petroleum industry increased 4% ($185 million) to $4.9 billion in the first nine months of 1990 from $4.7 billion in the corresponding 1989 period. Capital expenditures, net of grants and incentives, rose 6% as incentives dropped 78% to $30 million from $130 million in the first nine months of 1989 (Table 9.5).

Table 9.3 Capital Expenditures and Reinvestment Rates

First Nine Months

	1989	1990	Change	
	--- $	billions ---		(%)
Gross Capital Expenditures	4.7	4.9	0.2	4
Less: Incentive Grants	0.1	-	-0.1	-78
Net Capital Expenditures	4.6	4.9	0.3	6
Reinvestment Rate: Net Capital Expenditures as a Per Cent of Cash Flow	80%	89%		

Exploration and development outlays, including incentives and insurance receipts, increased 2% to $2.6 billion in the first nine months of 1990, whereas other capital expenditures increased 7% to $2.2 billion. Gross capital outlays for Canadian-controlled companies rose 17% to $2.2 billion, while those of foreign-controlled companies fell 5% to $2.7 billion.

The total reinvestment rate rose to 89% in the first nine months of 1990 from 80% in the corresponding 1989 period due to the decrease in cash flow and the increase in capital expenditures (Table 9.4). The reinvestment rate for Integrateds and Refiners increased to 81% from 77%, while that of the Oil and Gas Producers group rose to 96% from 82%.

Figure 9.4 Capital Expenditures and Reinvestment Rates: 1981-1990

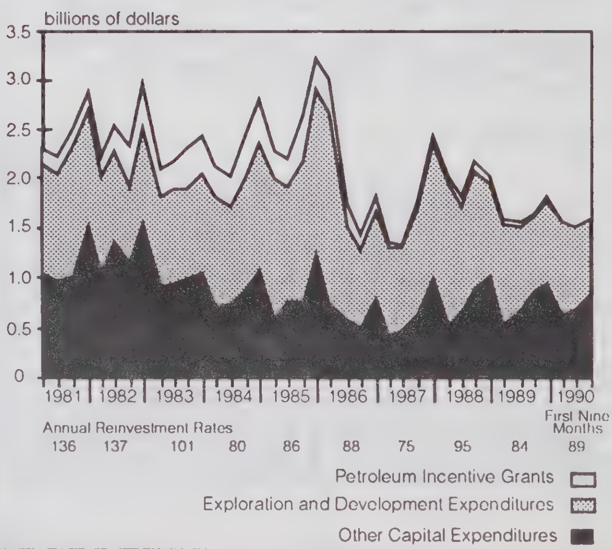


Table 9.4 Total Capital Expenditures (Net Of Incentive Grants) as a Per Cent of Internal Cash Flow

First Nine Months

	1989	1990
	-------(%)------	
Integrateds and Refiners	77	81
Canadian-Controlled	108	120
Foreign-Controlled	70	72
Senior Oil and Gas Producers	71	80
Canadian-Controlled	66	74
Foreign-Controlled	74	86
Junior Oil and Gas Producers	110	128
Canadian-Controlled	108	132
Foreign-Controlled	115	119
Oil and Gas Producers	82	96
Canadian-Controlled	84	97
Foreign-Controlled	81	94
Total Industry	**80**	**89**
Canadian-Controlled	89	102
Foreign-Controlled	75	81

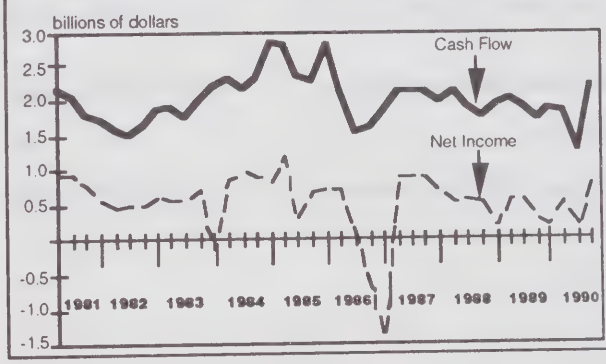
Third Quarter 1990:

Net Income for the third quarter of 1990 rose $505 million to $765 million from $260 million for the corresponding 1989 period due mainly to the substantial crude oil price rise following the Persian Gulf crisis. While sales revenues rose 15% or $1.4 billion, the main categories of expenses, with the exception of income taxes, grew less rapidly. Moreover, lower interest expenses, reduced E&D expenses charged to current operations and lower write-offs contributed to the increase in net income. As a result, net income before income taxes rose $910 million to $1.3 billion. However, an increase in both current and deferred income taxes of $355 million and $50 million respectively kept the net income rise to just over $500 million. Internal cash flow rose 31% to $2.3 billion.

Overall capital expenditures in the third quarter of 1990 rose 4% to $1.7 billion. Exploration and development spending rose 1% to $805 million, while other capital expenditures increased 7% to $935 million.

The reinvestment rate in the third quarter of 1990 was 77%, down from 95% for the corresponding 1989 period.

Figure 9.5 Net Income and Cash Flow 1981-1990: Quarterly Data



Note: This report was prepared on the basis of the quarterly data submitted by individual companies to the PMA via Statistics Canada. In contrast to the bi-annual PMA survey presentation, the report covers the combined results of upstream, downstream and other Canadian operations but excludes the results of companies' foreign activities. Nonetheless, the information contained in this analysis gives a reliable overview of the industry's financial performance for the first nine months of 1990.

Table 9.5

Capital Expenditures of Petroleum Industry
First Nine Months

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1989	1990	Change %	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions			$ millions		
Exploration and Development									
E&D Expensed									
Land & Lease Acquisition and Retention	49	62	27	7	9	42	43	52	22
Drilling Expenditures	401	274	-32	154	140	-9	246	134	-46
Geological and Geophysical	260	258	-1	23	28	22	238	231	-3
Total E&D Expensed	710	594	-16	184	177	-4	527	417	-21
E&D Capitalized									
Land & Lease Acquisition and Retention	407	530	30	165	280	70	242	250	3
Drilling Expenditures	1281	1306	2	625	793	27	656	513	-22
Geological and Geophysical	199	205	3	133	140	5	66	66	-1
Total E&D Capitalized	1887	2041	8	923	1213	31	964	829	-14
Total Exploration and Development	**2597**	**2635**	2	**1107**	**1390**	**26**	**1491**	**1246**	**-16**
Other Capitalized Expenditures									
Mining	122	65	-47	42	22	-48	80	42	-48
New Const., Build., Mach., and Equip.	1663	1749	5	620	651	5	1043	1098	5
Used Build., Mach., Equip., & Land	151	269	78	61	73	20	90	196	-
Other Capital Expenditures	147	148	1	47	55	17	101	93	-8
Total Other Capital Expenditures	2083	2231	7	770	801	4	1314	1429	9
Total Capital Expenditures	**4680**	**4866**	**4**	**1877**	**2191**	**17**	**2805**	**2675**	**-5**
Capital Grants	129	29	-78	70	14	-80	59	16	-73
Net Capital Expenditures	**4551**	**4837**	**6**	**1807**	**2177**	**20**	**2746**	**2659**	**-3**

Table 9.6

Capital Expenditures of Petroleum Industry
Third Quarter

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1989	1990	Change %	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions			$ millions		
Exploration and Development									
E&D Expensed									
Land & Lease Acquisition and Retention	17	19	15	1	4	-	15	15	-2
Drilling Expenditures	152	97	-36	71	35	-51	81	62	-23
Geological and Geophysical	77	77	-	7	6	-14	70	71	2
Total E&D Expensed	246	193	-22	80	45	-44	166	148	-11
E&D Capitalized									
Land & Lease Acquisition and Retention	169	201	19	56	109	95	113	92	-19
Drilling Expenditures	330	355	8	201	226	12	129	128	-
Geological and Geophysical	52	58	12	35	36	3	17	22	29
Total E&D Capitalized	551	614	11	292	371	27	259	242	-7
Total Exploration and Development	**797**	**807**	**1**	**372**	**416**	**12**	**425**	**390**	**-8**
Other Capitalized Expenditures									
Mining	43	19	-56	18	1	-	25	18	-29
New Const., Build., Mach., and Equip.	733	719	-2	219	229	5	514	490	-5
Used Build., Mach., Equip., & Land	52	139	-	29	29	-1	22	110	-
Other Capital Expenditures	48	59	23	16	23	-13	31	36	16
Total Other Capital Expenditures	876	936	7	282	282	-	592	654	10
Total Capital Expenditures	**1673**	**1743**	**4**	**654**	**698**	**7**	**1017**	**1044**	**3**
Capital Grants	35	7	-80	14	2	-86	21	5	-76
Net Capital Expenditures	**1638**	**1736**	6	**640**	**696**	**9**	**996**	**1039**	**4**

Table 9.7

Income Statement
First Nine Months

	Total Industry 1989	1990	Change %	Canadian-Controlled 1989	1990	Change %	Foreign-Controlled 1989	1990	Change %
	$ millions			$ millions			$ millions		
Sales Revenues	29593	32468	10	9702	10969	13	19891	21498	8
Other Revenues									
Interest from Canadian Sources	350	298	-15	153	139	-9	197	159	-19
Dividends from Canadian Corporations	51	63	22	31	52	71	21	10	-51
Foreign Dividends and Interest Revenues	23	13	-43	14	-	-97	9	12	37
Gains on Sale of Assets	70	500	-	17	33	98	53	467	-
Total Revenues	**30086**	**33341**	**11**	**9915**	**11193**	**13**	**20171**	**22147**	**10**
Expenses									
E & D Expensed	789	613	-22	196	178	-9	594	435	-27
D, D & A Charges	3622	3884	7	1427	1610	13	2194	2274	4
Other Expenses	21979	24632	12	7003	7990	14	14976	16642	11
Interest Expenses	1781	1762	-1	717	806	12	1064	956	-10
Total Operating Expenses	**28171**	**30890**	**10**	**9343**	**10584**	**13**	**18828**	**20306**	**8**
Other Transactions									
Gains on Translation of Currency	94	122	30	22	-5	-	71	127	78
Write-offs and Valuation Adjustments	-91	-143	-	-27	-91	-	-63	-52	-
Income before Income Taxes	**1919**	**2429**	**27**	**567**	**513**	**-10**	**1352**	**1916**	**42**
Income Taxes									
Current	558	1032	85	151	228	50	407	804	98
Deferred (tax allocation method)	298	181	-39	58	89	53	240	92	-62
Net Income after Income taxes	**1062**	**1217**	**15**	**358**	**197**	**-45**	**705**	**1020**	**45**
Other Income									
Equity Income	198	166	-16	120	75	-38	78	92	18
Extraordinary Items	14	-	-	11	-	-	4	-	-
Net Income after Extraordinary Items	**1275**	**1383**	**9**	**488**	**272**	**-44**	**787**	**1112**	**41**
Cash Flow	**5698**	**5416**	**-5**	**2027**	**2137**	**5**	**3671**	**3279**	**-11**

	Integrateds and Refiners 1989	1990	Change %	Oil and Gas Producers 1989	1990	Change %
	$ millions			$ millions		
Sales Revenues	19281	21167	10	10311	11300	10
Other Revenues						
Interest from Canadian Sources	162	136	-16	187	163	-13
Dividends from Canadian Corporations	5	7	28	46	56	21
Foreign Dividends and Interest Revenues	-	-	-	22	13	-44
Gains on Sale of Assets	33	431	-	37	69	88
Total Revenues	**19482**	**21741**	**12**	**10604**	**11600**	**9**
Expenses						
E & D Expensed	237	191	-19	553	422	-24
D, D & A Charges	1392	1580	14	2229	2304	3
Other Expenses	15752	17576	12	6227	7056	13
Interest Expenses	745	775	4	1036	987	-5
Total Operating Expenses	**18126**	**20122**	**11**	**10045**	**10768**	**7**
Other Transactions						
Gains on Translation of Currency	19	44	-	75	78	5
Write-offs and Valuation Adjustments	-24	-34	-	-67	-109	-
Income before Income Taxes	**1351**	**1628**	**21**	**568**	**801**	**41**
Income Taxes						
Current	440	618	41	119	414	-
Deferred (tax allocation method)	132	88	-33	166	93	-44
Net Income after Income taxes	**780**	**923**	**18**	**283**	**294**	**4**
Other Income						
Equity Income	58	29	-50	141	138	-2
Extraordinary Items	2	-	-	13	-	-
Net Income after Extraordinary Items	**839**	**951**	**13**	**435**	**432**	**-1**
Cash Flow	**2513**	**2341**	**-7**	**3186**	**3075**	**-4**

Table 9.8

Income Statement
Third Quarter

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1989	1990	Change %	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions			$ millions		
Sales Revenues	9990	11439	15	3303	3910	18	6687	7529	13
Other Revenues									
Interest from Canadian Sources	119	89	-25	58	41	-29	61	49	-21
Dividends from Canadian Corporations	19	20	6	14	17	26	6	3	-42
Foreign Dividends and Interest Revenues	9	6	-35	5	-	-91	4	5	31
Gains on Sale of Assets	39	70	77	6	-14	-	33	83	-
Total Revenues	**10176**	**11624**	**14**	**3385**	**3954**	**17**	**6791**	**7670**	**13**
Expenses									
E & D Expensed	272	202	-26	85	46	-46	187	156	-17
D, D & A Charges	1168	1273	9	463	527	14	705	746	6
Other Expenses	7694	8273	8	2465	2750	12	5229	5523	6
Interest Expenses	623	569	-9	265	275	4	358	294	-18
Total Operating Expenses	**9757**	**10317**	**6**	**3277**	**3598**	**10**	**6480**	**6719**	**4**
Other Transactions									
Gains on Translation of Currency	65	51	-22	9	-10	-	57	61	7
Write-offs and Valuation Adjustments	-44	-9	-	-17	-1	-	-28	-9	
Income before Income Taxes	**440**	**1348**	**-**	**100**	**345**	**-**	**340**	**1002**	**-**
Income Taxes									
Current	88	445	-	53	112	-	34	333	-
Deferred (tax allocation method)	154	204	33	4	66	-	149	138	-7
Net Income after Income taxes	**199**	**699**	**-**	**42**	**168**	**-**	**157**	**531**	**-**
Other Income									
Equity Income	58	66	14	23	16	-30	35	50	43
Extraordinary Items	3	-	-	2	-	-	1	-	-
Net Income after Extraordinary Items	**260**	**765**	**-**	**68**	**184**	**-**	**193**	**582**	**-**
Cash Flow	**1732**	**2267**	**31**	**596**	**831**	**39**	**1136**	**1436**	**26**

	Integrateds and Refiners			Oil and Gas Producers		
	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions		
Sales Revenues	6609	7377	12	3381	4061	20
Other Revenues						
Interest from Canadian Sources	41	39	-6	78	51	-35
Dividends from Canadian Corporations	1	3	-	18	18	-4
Foreign Dividends and Interest Revenues	-	-	-	9	6	-36
Gains on Sale of Assets	-4	3	-	43	67	54
Total Revenues	**6646**	**7421**	**12**	**3530**	**4202**	**19**
Expenses						
E & D Expensed	76	73	-3	197	128	-35
D, D & A Charges	440	517	18	729	756	4
Other Expenses	5611	5787	3	2083	2486	19
Interest Expenses	261	246	-6	362	323	-11
Total Operating Expenses	**6387**	**6624**	**4**	**3370**	**3694**	**10**
Other Transactions						
Gains on Translation of Currency	14	32	-	51	19	-63
Write-offs and Valuation Adjustments	-4	-3	-	-40	-7	-
Income before Income Taxes	**270**	**826**	**-**	**170**	**521**	**-**
Income Taxes						
Current	62	337	-	26	108	-
Deferred (tax allocation method)	67	52	-23	87	153	75
Net Income after Income taxes	**141**	**438**	**-**	**58**	**261**	**-**
Other Income						
Equity Income	18	4	-79	42	63	50
Extraordinary Items	2	-	-	2	-	-
Net Income after Extraordinary Items	**160**	**442**	**-**	**100**	**323**	**-**
Cash Flow	**717**	**1048**	**46**	**1016**	**1219**	**20**

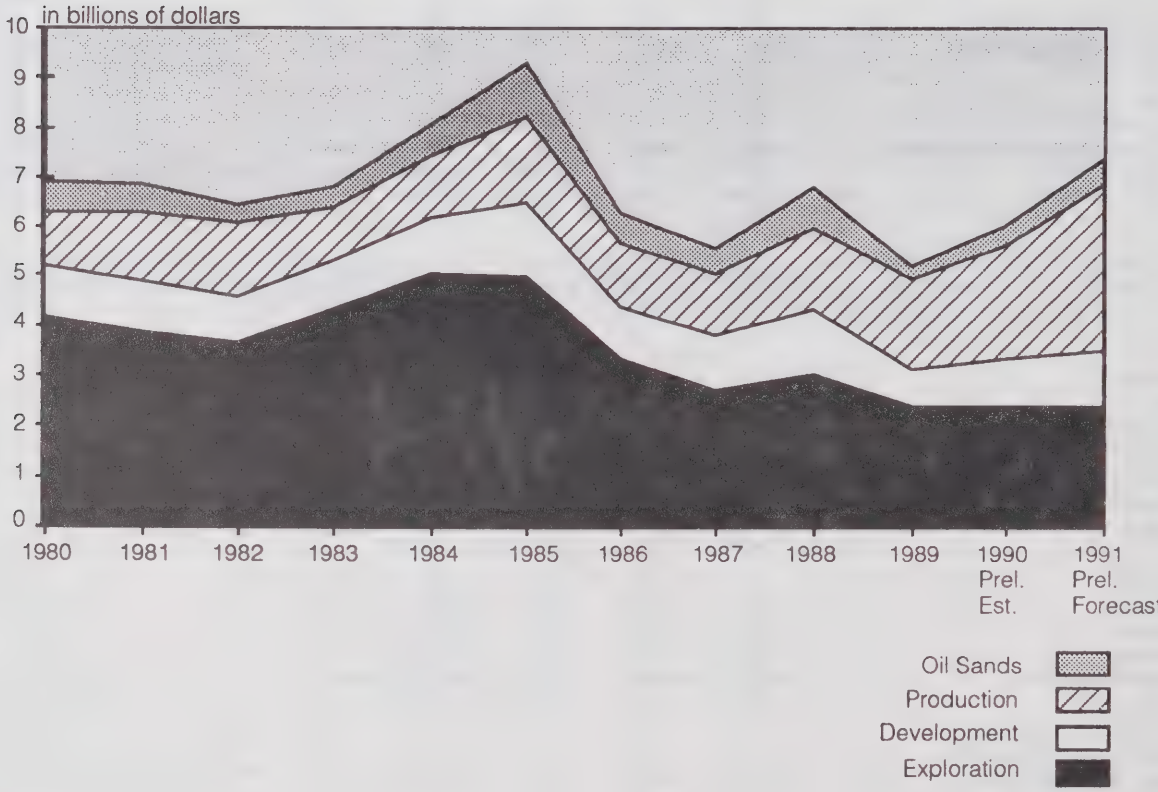
10. Petroleum Industry Capital Expenditures: Preliminary Forecast 1991, Preliminary Estimate 1990 and Actual 1989

- *Industry's upstream expenditures for 1991 are forecast to rise 24% to $7.4 billion over estimated 1990 spending of $5.9 billion and 42% over actual 1989 outlays of $5.2 billion.*
- *Production spending, showing the largest increase, is expected to rise 49% to $3.4 billion in 1991 over 1990 estimates.*
- *Total exploration expenditures are forecast to be unchanged at $2.4 billion in 1991 compared with 1990 preliminary estimates and actual 1989 level.*

Upstream capital expenditures estimates for 1990 and forecasts for 1991 were filed by reporting companies in December 1990 and early January 1991 during a period that witnessed sharp fluctuations in crude oil prices. The data, made available to the PMA via Statistics Canada, show that industry's upstream expenditures for 1991 are forecast to rise 24% to $7.4 billion over the estimated 1990 spending of $5.9 billion and 42% over the actual capital expenditures of $5.2 billion in 1989.

Preliminary estimates of 1990 capital expenditures indicate a 15% increase over the low 1989 capital outlays -- representing the lowest level in a decade.

Figure 10.1 Upstream Canadian Expenditures - by Type



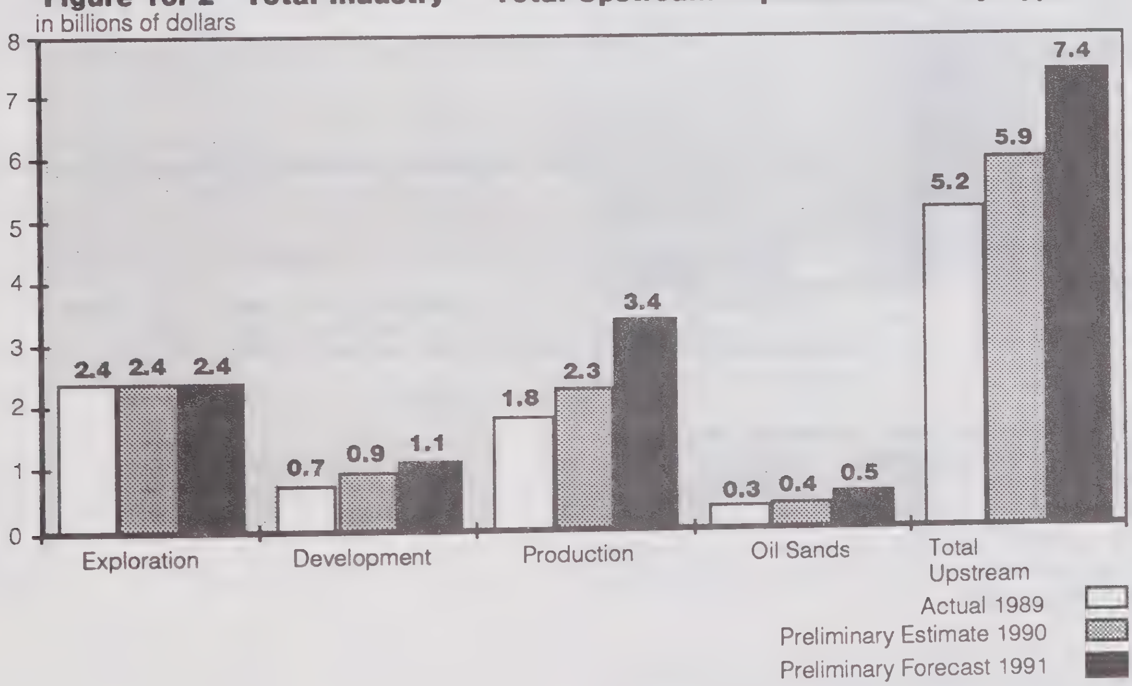
This expected improvement in capital spending over 1989 actual outlays is primarily the result of spending on major projects, such as the Other Six Leases Operation (OSLO) oil sands project and the Bi-provincial heavy oil upgrader, which resumed in 1990 and are expected to continue through 1991. Also, other projects, such as the development of the Caroline gas field, the Hibernia (offshore Newfoundland) and the Panuke/Cohasset oil field developments, are expected to enter into the production phase in 1991.

All categories of upstream expenditures but exploration spending are forecast to increase in 1991; exploration spending is anticipated to remain virtually unchanged at $2.4 billion over the estimated 1990 and actual 1989 capital outlays. Annual exploration expenditures of $2.4 billion for the three periods under review represent the lowest levels of outlays in a decade. Crude oil prices have increased markedly, on average, in the second half of 1990 due to supply fears. However, during the same period the accompanying sharp price fluctuations underlined the industry's uncertainty with regard to future crude oil prices -- negatively affecting exploration budgets.

Development expenditures are forecast to increase 21% to $1.1 billion in 1991 over preliminary 1990 outlays. Most companies reported that they anticipated higher capital outlays on development. This broadly based increase may be an indication that companies are attempting to put more oil prospects on stream in the short term in an effort to obtain the benefits of higher crude oil prices.

The most significant increase in total upstream capital expenditures is forecast to be in production spending -- up 49% to $3.4 billion from the preliminary estimate of 1990 -- mainly on production facilities. A substantial rise is expected in production spending on Canada Lands, the Caroline gas field development, and the Bi-provincial heavy oil upgrader. Government incentives are expected to provide the impetus for the Hibernia project in 1991.

Figure 10. 2 Total Industry - Total Upstream Expenditures - by Type



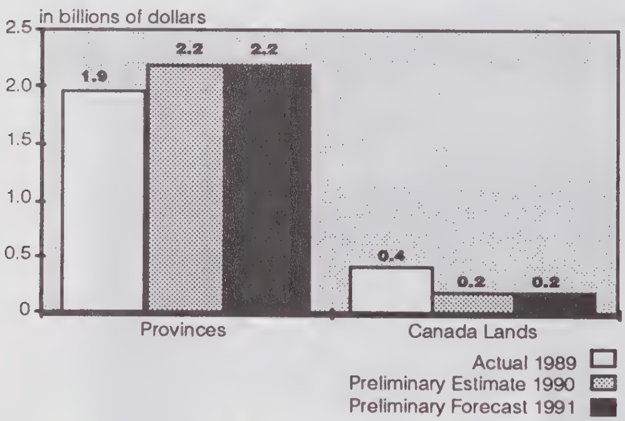
Capital outlays for oil sands are expected to rise 31% to $535 million in 1991. This is partly due to existing projects requiring additional machinery and equipment as well as increase spending on tailing disposal systems.

Total upstream expenditures in the provinces are forecast to rise 15% to $6.5 billion in 1991 over $5.7 billion anticipated in 1990, while spending on Canada Lands is projected to increase $580 million to $880 million over the same period.

Exploration Expenditures: Total exploration expenditures are forecast to remain unchanged at $2.4 billion in 1991 from preliminary estimates in 1990 and actual spending in 1989.

Compared to the 1989 level, exploration spending on provincial lands is expected to be approximately 14% higher in both 1990 and 1991 periods. This increase is forecasted to be offset by reductions in outlays on Canada's frontier territories (Table 1 and Chart 3). Provincial exploration expenditures are expected to account for 93% of total exploration activity in 1991 and 1990 vs. 83% in 1989.

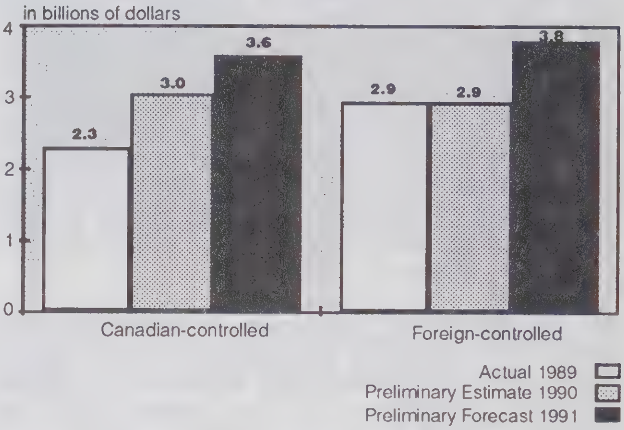
Figure 10.3 Total Exploration Expenditures



Canadian-Controlled versus Foreign-Controlled Companies: Upstream capital expenditures in 1991, compared to the preliminary estimates for 1990, are projected to increase 19% to $3.6 billion for the Canadian-controlled companies and 30% to $3.8 billion for the foreign-controlled companies.

Foreign-controlled companies are expected to account for 51% of total upstream outlays in 1991 compared with 49% of the 1990 estimates and 56% of the actual 1989 capital expenditures.

Figure 10.4 Total Upstream Expenditures



Canadian and foreign-controlled companies project an increase in all categories of expenditures for 1991 over 1990 estimates with the exception of exploration spending, which is expected to remain virtually unchanged. Production spending is expected to rise for production facilities and natural gas processing plants.

Table 10.1
Upstream Canadian Capital Expenditures by Control and Location in millions of dollars

	Total Canada				Provinces				Canada Lands			
	Actual 1989	Prel. Est. 1990	Prel. Fore. 1991	Forecast 1991 / Est. 1990 Change %	Actual 1989	Prel. Est. 1990	Prel. Fore. 1991	Forecast 1991 / Est. 1990 Change %	Actual 1989	Prel. Est. 1990	Prel. Fore. 1991	Forecast 1991 / Est. 1990 Change %
Total Industry												
Exploration	2365	2377	2388	-	1953	2208	2220	1	412	169	168	-1
Development	719	911	1100	21	718	910	1083	19	1	1	17	-
Production	1804	2270	3389	49	1773	2143	2695	26	31	127	694	-
Oil Sands	304	409	534	31	304	409	534	31	-	-	-	-
Total Upstream	5192	5967	7411	24	4748	5670	6532	15	444	297	879	196
Foreign - Controlled Companies												
Exploration	1276	1135	1131	-	955	997	993	-	321	138	138	-
Development	327	449	580	29	326	449	571	27	1	-	9	-
Production	1125	1130	1785	58	1119	1063	1429	34	6	67	356	-
Oil Sands	199	215	312	45	199	215	312	45	-	-	-	-
Total Upstream	2927	2929	3808	30	2599	2724	3305	21	328	205	503	145
Canadian - Controlled Companies												
Exploration	1090	1242	1257	1	998	1211	1227	1	91	31	30	-3
Development	393	463	520	12	392	461	512	11	1	1	8	-
Production	680	1140	1604	41	654	1080	1266	17	26	60	338	-
Oil Sands	105	194	222	14	105	194	222	14	-	-	-	-
Total Upstream	2268	3039	3603	19	2149	2946	3227	10	118	92	376	-

Table 10.2
Upstream Canadian Capital Expenditures by Selected Locations in millions of dollars

	Provinces											
	Alberta				British Columbia				Saskatchewan			
	Actual 1989	Prel. Est. 1990	Prel. Fore. 1991	Forecast 1991 / Est. 1990 Change %	Actual 1989	Prel. Est. 1990	Prel. Fore. 1991	Forecast 1991 / Est. 1990 Change %	Actual 1989	Prel. Est. 1990	Prel. Fore. 1991	Forecast 1991 / Est. 1990 Change %
Exploration	1545	1678	1694	1	315	407	417	2	85	111	112	1
Development	495	680	834	23	75	108	109	1	72	106	108	2
Production	1522	1507	1934	28	137	137	183	34	108	470	572	22
Oil Sands	304	409	534	31	-	-	-	-	-	-	-	-
Total Upstream	3866	4274	4996	17	527	652	709	9	265	687	792	15

Appendix I
Production of Canadian Crude Oil and Equivalent

		1989			1990		
		3Q	4Q	Year	1Q	2Q	3Q
		(000 m^3/d)					
A.	**Light and Equivalent**						
	Alberta	122.1	121.9	124.3	119.2	111.8	117.7
	B.C.	4.9	6.0	5.2	5.6	5.0	5.1
	Saskatchewan	10.6	10.5	10.6	11.2	11.6	12.4
	Manitoba	2.0	2.0	1.9	2.0	2.0	2.0
	Ontario	0.7	0.7	0.7	0.7	0.7	0.6
	Other	4.9	5.1	4.9	5.1	5.0	4.9
	Total	**145.2**	**146.2**	**147.6**	**143.8**	**136.1**	**142.7**
	Synthetic						
	Suncor	9.8	8.5	9.1	9.2	5.0	8.3
	Syncrude	21.6	24.4	23.6	15.9	28.9	26.7
	Total	**31.4**	**32.9**	**32.7**	**25.1**	**33.9**	**35.0**
	Pentanes Plus*	**7.4**	**9.0**	**7.8**	**6.1**	**7.2**	**6.3**
	Total Light	**184.0**	**188.1**	**188.1**	**175.0**	**177.2**	**184.0**
B.	**Heavy Crude**						
	Alberta						
	Conventional	25.6	27.2	25.2	26.9	26.6	27.2
	Bitumen	21.6	18.9	20.5	21.4	19.4	21.8
	Diluent	7.7	8.0	8.2	9.7	7.5	8.4
	Total	**54.9**	**54.1**	**53.9**	**58.0**	**53.5**	**57.4**
	Saskatchewan						
	Conventional	21.5	21.7	21.1	21.0	21.3	21.1
	Diluent	2.4	2.7	2.6	3.0	2.7	2.5
	Total	**23.9**	**24.4**	**23.7**	**24.0**	**24.0**	**23.6**
	Total Heavy	**78.8**	**78.5**	**77.6**	**82.0**	**77.5**	**81.0**
C.	**Production**	**262.7**	**266.6**	**265.6**	**257.0**	**254.7**	**265.0**
D.	**Shut-In**						
	Light	6.3	3.1	5.3	6.1	9.7	3.7
	Heavy	2.4	1.4	2.9	2.2	0.5	0.0
	Total	**8.7**	**4.5**	**8.2**	**8.3**	**10.2**	**3.7**
E.	**Total Capacity**	**271.5**	**271.1**	**273.9**	**265.3**	**264.9**	**268.7**

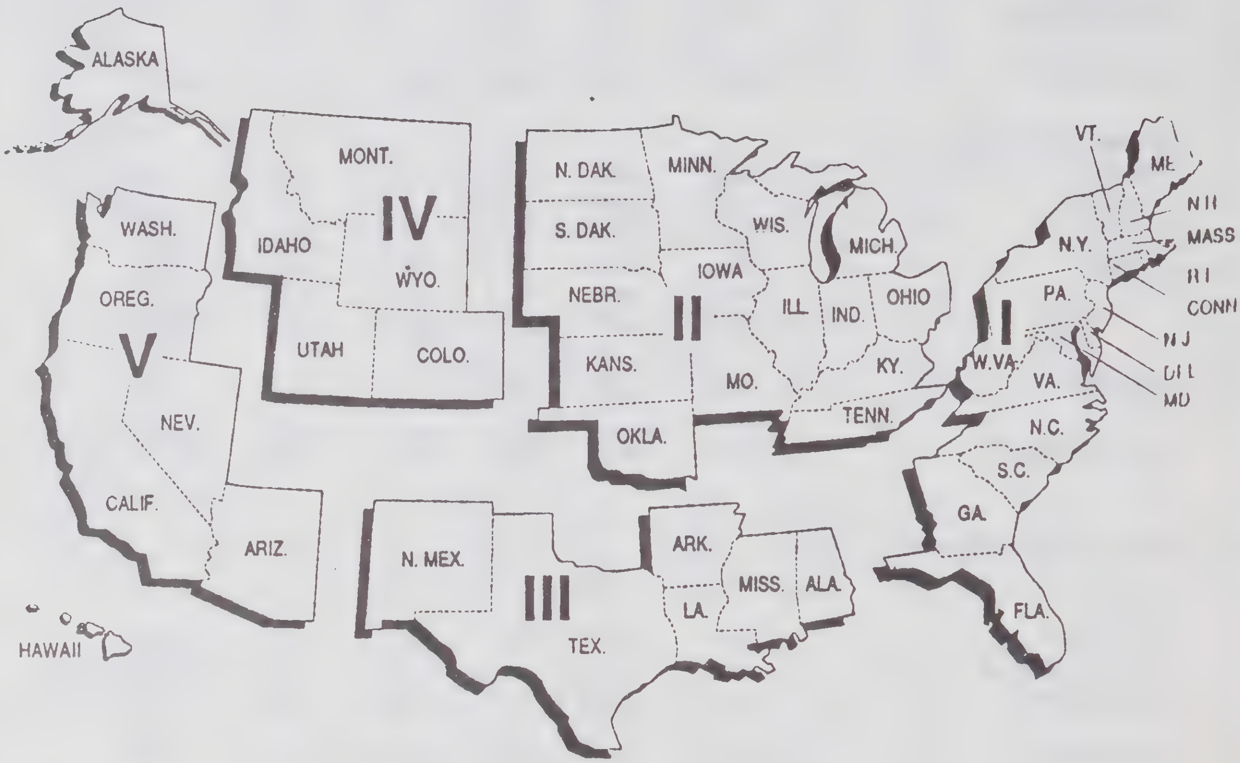
** excludes diluent*

Appendix II

Supply and Disposition of Canadian Crude Oil and Equivalent

	1989 3Q	1989 4Q	1989 Year	1990 1Q	1990 2Q	1990 3Q
	(000 m^3/d)					
A. Light and Equivalent						
Supply						
Production	183.9	188.0	188.1	175.0	177.2	184.0
Newgrade	0.0	0.0	0.1	0.5	1.1	1.4
Draw/(Build)	4.6	1.4	2.8	6.2	-0.2	5.7
Net Supply	188.5	189.4	191.0	181.7	178.1	191.1
Domestic Demand						
Atlantic	0.0	0.0	0.0	0.0	0.0	0.0
Quebec	8.0	10.4	9.3	7.1	11.4	9.7
Ontario	57.1	67.3	64.6	67.6	55.4	65.8
Prairies	57.7	51.9	52.7	53.7	46.0	49.4
B.C.	18.1	16.3	17.3	17.7	17.4	18.8
Total	**140.9**	**145.9**	**143.9**	**146.0**	**130.2**	**143.7**
Exports	**47.7**	**43.5**	**47.2**	**35.6**	**48.0**	**47.4**
Total Demand	**188.6**	**189.4**	**191.1**	**181.6**	**178.2**	**191.1**
B. Heavy Crude (Blended)						
Supply						
Production	78.9	78.6	77.7	82.0	77.6	81.0
Recycled Diluent	1.4	1.1	1.2	0.5	1.3	1.5
Draw/(Build)	-4.1	-3.9	-1.1	0.2	2.0	3.7
Net Supply	76.2	75.8	77.8	82.7	80.9	86.2
Domestic Demand						
Atlantic	0	0.1	0.1	0	0.4	0.9
Quebec	4.4	3.7	4.3	5.1	4.9	4.1
Ontario	9.1	9.4	9.7	8.9	7.0	8.4
Prairies	8.5	4 .8	7.3	7.3	11.1	14.6
B.C.	0.5	0.8	0.6	0.2	0.3	0.4
Total	**22.5**	**18.9**	**21.9**	**21.6**	**23.6**	**28.4**
Exports	**53.7**	**56.8**	**55.7**	**61.1**	**57.3**	**57.8**
Total Demand	**76.2**	**75.7**	**77.6**	**82.7**	**80.9**	**86.2**

Appendix III
U.S. Petroleum Administration for Defense (PAD) Districts



Appendix IV

Crude Oil Exports by Destination

U.S. PAD* Districts		1989 3Q	1989 4Q	1989 Year	1990 1Q	1990 2Q	1990 3Q
		(000 m^3/d)					
PADD I	Light	7.2	7.5	7.4	6.3	7.8	7.8
	Heavy	1.2	1.2	1.3	1.8	1.1	1.2
	Total	**8.4**	**8.7**	**8.7**	**8.1**	**8.9**	**9.0**
PADD II	Light	26.9	24.5	27.3	19.0	29.2	28.4
	Heavy	49.2	50.0	48.3	50.5	50.3	52.5
	Total	**76.1**	**74.5**	**75.6**	**69.5**	**79.5**	**80.9**
PADD III	Light	0.0	0.0	0.0	0.0	0.0	0.0
	Heavy	0.0	1.2	1.5	3.3	1.4	0.0
	Total	**0.0**	**1.2**	**1.5**	**3.3**	**1.4**	**0.0**
PADD IV	Light	10.6	8.9	9.1	9.0	9.5	10.5
	Heavy	2.6	1.5	2.7	2.3	2.9	3.4
	Total	**13.2**	**10.4**	**11.8**	**11.3**	**12.4**	**13.9**
PADD V	Light	2.1	2.5	2.8	0.7	1.3	0.8
	Heavy	0.8	0.4	0.6	0.8	0.8	0.8
	Total	**2.9**	**2.9**	**3.4**	**1.5**	**2.1**	**1.6**
U.S.	**Light**	**46.8**	**43.4**	**46.6**	**35.0**	**47.8**	**47.5**
	Heavy	**53.8**	**54.3**	**54.4**	**58.7**	**56.5**	**57.9**
	Total	**100.6**	**97.7**	**101.0**	**93.7**	**104.3**	**105.4**
Offshore	Light	0.0	0.0	0.4	0.4	0.0	0.0
	Heavy	0.9	2.5	1.4	2.5	0.8	0.0
	Total	**0.9**	**2.5**	**1.8**	**2.9**	**0.8**	**0.0**
Total	**Light**	**47.7**	**43.4**	**47.0**	**35.4**	**47.8**	**47.5**
	Heavy	**53.8**	**56.8**	**55.8**	**61.2**	**57.3**	**57.9**
		101.5	**100.2**	**102.8**	**96.6**	**105.1**	**105.4**

* *U.S. Petroleum Administration for Defense (PAD) Districts*

Appendix V
Pipeline Deliveries

	1989 3Q	1989 4Q	1989 Year	1990 1Q	1990 2Q	1990 3Q
	(000 m^3/d)					
A. Trans Mountain Pipe Line (TMPL)						
Domestic Deliveries						
Light Crude Oil	14.3	12.9	13.9	13.5	14.4	15.4
Heavy Crude Oil	0.5	0.5	0.6	0.2	0.3	0.3
Semi Refined Products	5.2	6.2	5.4	5.1	5.0	5.6
Refined Products	2.7	3.0	2.7	2.7	2.7	2.6
Total	**22.7**	**22.6**	**22.7**	**21.5**	**22.4**	**23.9**
Foreign Deliveries						
Tankers	1,2	3,8	2.7	4.4	1.6	0.7
Puget Sound Area	1.9	2.4	2.7	0.7	1.3	0.9
Total	**3.1**	**6.2**	**5.4**	**5.1**	**2.9**	**1.6**
Total TMPL	**25.8**	**28.8**	**28.1**	**26.6**	**25.3**	**25.5**
B. Interprovincial Pipe Line (IPL)						
Domestic Deliveries						
Light Crude Oil	91.0	94.9	93.9	93.3	78.7	88.6
Heavy Crude Oil	15.9	16.1	17.9	19.7	17.5	17.9
Other (1)	25.0	27.6	26.4	27.6	28.0	23.1
Total	**131.9**	**138.6**	**139.9**	**140.6**	**124.2**	**129.6**
Foreign Deliveries (2)						
Light Crude Oil	41.2	38.9	42.0	33.4	46.3	42.3
Heavy Crude Oil	50.1	51.4	49.6	52.3	51.4	53.9
Total	**91.3**	**90.3**	**91.6**	**85.7**	**97.7**	**96.2**
Total IPL	**223.2**	**228.9**	**231.5**	**226.3**	**221.9**	**225.8**
C. Pipeline to Montreal						
IPL Deliveries						
To Montreal Refineries	13.5	15.1	14.5	12.5	16.3	14.3
For Export/Transfer	0.0	2.5	2.0	4.5	0.4	0.6
Total IPL	**13.5**	**17.6**	**16.4**	**17.0**	**16.7**	**14.9**
Portland-Montreal						
Montreal Imports (3)	15.7	12.5	13.2	16.8	9.2	17.9
Total Mtl Receipts	**29.2**	**27.6**	**27.6**	**29.3**	**25.5**	**32.2**

Note (1): includes petroleum products and NGL's.
(2): includes US domestic crudes delivered to the US.
(3): includes cargoes imported directly into Montreal

Appendix VI
Refinery Receipts

	1989 3Q	1989 4Q	1989 Year	1990 1Q	1990 2Q	1990 3Q
	(000 m^3/d)					
A. Domestic Receipts						
Light & Equivalent						
Atlantic	0.0	0.0	0.0	0.0	0.0	0.0
Quebec	8.0	10.4	9.3	7.1	11.4	9.7
Ontario	57.2	67.3	64.6	67.5	55.3	65.8
Prairies	57.7	51.8	52.7	53.7	46.0	49.5
B.C.	18.1	16.3	17.3	17.6	17.4	18.9
Total	**141.0**	**145.8**	**143.8**	**145.9**	**130.1**	**143.9**
Heavy						
Atlantic	0.0	0.1	0.0	0.0	0.4	0.9
Quebec	4.4	3.7	4.3	5.2	4.9	4.2
Ontario	9.1	9.4	9.7	8.8	7.0	8.4
Prairies	8.5	4.9	7.3	7.4	11.1	14.5
B.C.	0.5	0.8	0.6	0.2	0.3	0.4
Total	**22.5**	**18.9**	**21.9**	**21.6**	**23.7**	**28.4**
Other Receipts*						
Atlantic	0.2	0.5	0.8	0.8	0.5	0.2
Quebec	1.5	1.1	1.2	1.4	1.1	0.4
Ontario	4.3	4.8	4.3	3.3	3.9	2.6
Prairies	3.4	4.0	3.4	3.4	2.6	2.9
B.C.	5.7	5.9	5.9	5.3	5.0	5.9
Total	**15.1**	**16.3**	**15.5**	**14.2**	**13.1**	**12.0**
Total Domestic Receipts						
Atlantic	0.2	0.6	0.8	0.8	0.9	1.1
Quebec	13.9	15.2	14.8	13.7	17.4	14.3
Ontario	70.6	81.5	78.6	79.6	66.2	76.8
Prairies	69.6	60.7	63.4	64.5	59.7	66.9
B.C.	24.3	23.0	23.7	23.1	22.7	25.2
Total	**178.6**	**181.0**	**181.1**	**181.7**	**166.9**	**184.2**
B. Crude Oil Imports						
Atlantic	45.7	47.6	46.3	50.7	47.3	48.3
Quebec	26.6	25.5	26.5	35.2	25.0	36.9
Ontario	8.0	2.9	4.2	5.1	2.6	2.1
Prairies	0.0	0.0	0.0	0.0	0.0	0.0
B.C.	0.0	0.0	0.0	0.0	0.0	0.0
Total	**80.3**	**76.0**	**77.0**	**91.0**	**74.9**	**87.3**
C. Total Receipts						
Atlantic	45.9	48.2	47.0	51.5	48.2	49.4
Quebec	40.5	40.7	41.3	48.9	42.4	51.2
Ontario	78.6	84.4	82.8	84.7	68.8	78.9
Prairies	69.6	60.7	63.4	64.5	59.7	66.9
B.C.	24.3	23.0	23.7	23.1	22.7	25.2
Total	**258.9**	**257.0**	**258.1**	**272.7**	**241.8**	**271.6**

* *Partially processed oil, gas plant butanes etc.*

Appendix VII

Monthly Crude Oil Prices

(US$/bbl)

A. At Source	Canadian Par	WTI NYMEX	Brent
Oct.	19.40	20.10	19.04
Nov.	19.16	19.83	19.13
Dec.	19.96	21.09	19.86
Jan.	21.66	22.64	21.10
Feb.	21.72	22.12	19.90
Mar.	20.18	20.41	18.44
Apr.	18.09	18.58	16.61
May	17.81	18.46	16.65
Jun.	16.07	16.86	15.56
Jul.	17.39	18.64	17.48
Aug.	26.25	27.18	27.40
Sep.	32.63	33.69	35.17

B. At Chicago	Canadian Par	WTI NYMEX	Brent
Oct.	20.57	20.63	20.76
Nov.	20.33	20.36	21.09
Dec.	21.13	21.63	21.62
Jan.	22.84	23.24	22.89
Feb.	22.88	22.72	21.64
Mar.	21.35	21.01	20.36
Apr.	19.37	19.18	18.43
May	19.09	19.06	18.43
Jun.	17.35	17.46	17.35
Jul.	18.69	19.24	19.27
Aug.	27.57	27.78	29.21
Sep.	33.94	34.29	37.08

C. At Montreal	Canadian Par	Brent
Oct.	20.73	20.69
Nov.	20.50	20.82
Dec.	21.31	21.65
Jan.	23.00	23.42
Feb.	23.04	22.05
Mar.	21.51	20.52
Apr.	19.59	18.63
May	19.31	18.07
Jun.	17.57	16.91
Jul.	18.91	18.86
Aug.	27.79	28.65
Sep.	34.15	36.68

Appendix VIII
Average Regular Unleaded Gasoline Prices
(Self-Serve)
1989-1990

	1989		1990		
	Sept. 26	Dec. 26	March 27	June 26	Sept. 25
	cents per litre				
St. John's (NFLD)	56.7	56.8	58.3	59.6	64.4
Charlottetown	54.1	53.8	56.2	57.7	58.5
Halifax *	52.4	52.4	53.8	57.5	56.3
Saint John (N.B.)*	53.9	51.9	55.2	55.9	60.1
Montreal	58.1	58.1	60.8	61.9	64.0
Toronto	51.3	47.2	48.5	53.9	59.3
Winnipeg	51.4	50.7	53.9	49.9	56.9
Regina	53.8	45.8	54.9	54.9	58.9
Calgary	48.1	48.1	51.9	53.3	55.7
Vancouver	54.1	54.9	59.9	59.9	64.9
Average	**53.6**	**52.1**	**54.8**	**56.8**	**60.8**
Consumption taxes included:					
Federal	11.0	11.0	12.1	12.1	12.2
Provincial	10.5	10.6	11.3	11.4	11.3

* *Full-serve*

Appendix IX
Consumption Taxes on Petroleum Products
(September 1, 1990)

	Ad valorem		Gasoline			
	Mogas	Diesel	Reg L	Reg UL	Prem UL	Diesel
	---------- % ----------		------------------ (cents per litre) ------------------			
FEDERAL TAXES						
Sales			3.74*	3.74	3.85*	2.88*
Excise			9.5	8.5*	8.5	4.0
PROVINCIAL TAXES						
Newfoundland(a)	23(b)	27	12.8	11.3	11.3	12.5
Prince Edward Island	23	26	11.3*	11.3*	11.3*	11.0*
Nova Scotia	22.25	31.5	10.7*	10.7*	10.7*	14.1
New Brunswick	24.5(c)	31.5	13.0*	11.2*	11.8*	11.6*
Quebec(d)			14.4	14.4	14.4	12.45
Ontario			14.3	11.3	11.3	10.9
Manitoba			10.8	9.0	9.0	9.9
Saskatchewan			12.0	10.0	10.0	10.0
Alberta			7.0	7.0	7.0	7.0
British Columbia(e)	22.5(f)		11.83*	9.83*	9.83*	10.27*
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	(g)	9.0*	9.0*	9.0*	7.7*

(a) *The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay in Labrador*

(b) *This applies to unleaded gasoline. The tax on leaded gasoline is 1.5 cents per litre higher than the unleaded tax.*

(c) *This applies to all gasoline. There is also a 2.2 cent per litre surcharge on regular leaded gasoline.*

(d) *Reduced by varying amounts in certain remote areas and within 20 kilometers of the provincial and U.S. borders*

(e) *Additional transit tax of 3.0 cents per litre in Vancouver.*

(f) *This applies to unleaded gasoline. Taxes on leaded gasoline and diesel fuel is 2.0 and 0.44 cents per litre higher, respectively, than the unleaded tax.*

(g) *85% of gasoline tax.*

* *Changed since last quarter.*

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional area	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Shut-in capacity	The unused production capability of currently producing oil and gas wells plus the total production capability of all shut-in oil and gas wells, regardless of whether or not they are connected to surface gathering and production facilities.
Synthetic crude oil	Crude oil produced treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

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Canada

THE ENERGY OF OUR RESOURCES
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THE CANADIAN OIL MARKET

Vol. VI, No. 4, Winter 1990

Canadian Oil Markets and Emergency Planning Division
Energy Sector
Energy, Mines and Resources Canada

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The Canadian Oil Market

Overview

The performance of the Canadian oil industry during 1990 and the fourth quarter of the year is reviewed in this publication, and where possible short-term outlooks have been included. The year was characterized by a continuing decline in domestic crude oil production and falling demand for refined petroleum products.

The decline in product demand was exacerbated during the fourth quarter of the year by warmer than usual weather, the deepening recession and the impact of the Persian Gulf crisis. Market uncertainty generated by the Gulf situation led to a rapid rise in crude and product prices.

Higher crude prices resulted in a substantial increase in producer revenues. This rise did not immediately translate into an increase in drilling activity as most of the incremental revenue was apparently directed to servicing industry debt. However, during the fourth quarter drilling activity exceeded expectations as the industry began to respond to higher prices.

Although domestic crude production had fallen in the first half of the year, production increased during the third and fourth quarters primarily on the strength of modest rise in conventional heavy production and near record synthetic output from Alberta's Syncrude and Suncor oil sands plants.

While exports of domestic crudes remained relatively stable through the year, imports, particularly into Montreal during the fourth quarter, rose significantly. North Sea crudes accounted for all of this increase with OPEC deliveries, mainly to Atlantic refiners, remaining steady.

Canada's oil trade surplus rose substantially in 1990. All the gain was confined to trade in refined petroleum products, as a significant rise in crude oil imports, compared to only a marginal increase in exports, precluded an increase in the crude oil surplus.

This issue of the Canadian Oil Market also includes a detailed review, prepared by the Petroleum Monitoring Agency, of the financial performance of the Canadian oil and gas industry in 1990.

The Canadian Oil Market

1. Refined Petroleum Product Demand

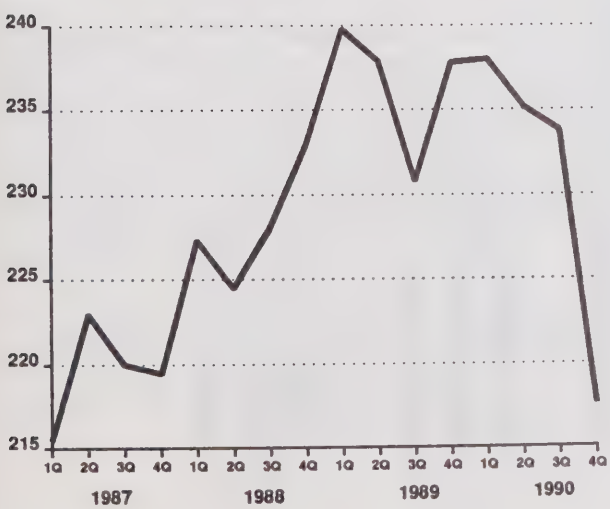
- *Sales of refined petroleum products fell as a result of a deepening recession, escalating prices during the fourth quarter and warmer than normal temperatures.*

- *According to a study published by the Energy Supplies Allocation Board, heavy fuel oil switching for emergency preparedness would be of limited effectiveness during a supply crisis situation.*

1.1 Seasonally Adjusted Demand

Total sales of refined petroleum products averaged 231 000 m^3/d during 1990, a decline of 2% from 1989, according to data issued by Statistics Canada. The downward trend in sales that began during the first quarter of 1990, continued throughout the year and by the fourth quarter had fallen to the lowest point in nearly three years. The drop in sales was consistent with the deepening recession and higher prices of petroleum products resulting from the conflict in the Persian Gulf.

Figure 1.1
Total Refined Product Consumption
(Seasonally adjusted)
000 m^3/d

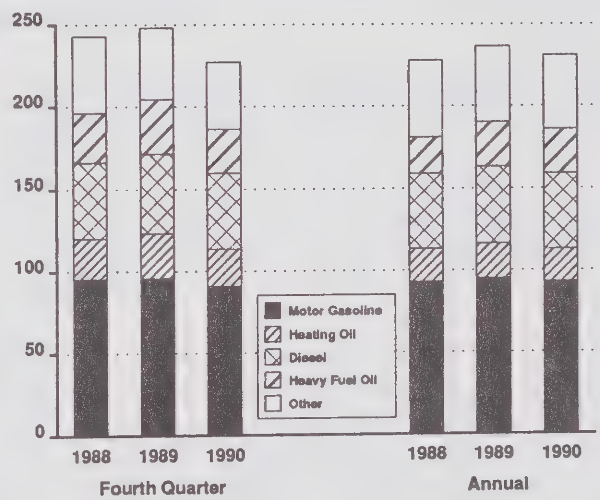


Demand for petroleum products in the fourth quarter plunged to 217 000 m^3/d. This represents a dramatic decline in sales of about 8% from the average of the three previous quarters and about 9% from fourth quarter sales in 1989.

1.2 Unadjusted Demand

All regions in Canada recorded a drop in petroleum product sales with the exception of British Columbia. Most of the decrease was the result of a 6% drop in Quebec and a 2% drop in Ontario.

Figure 1.2.1
Petroleum Product Consumption
000 m^3/d



The decline in sales was prominent in November, decreasing by 6% from the previous year before plumetting 18% in December. Lack of growth in the economy coupled with higher prices gave momentum to the downturn in demand in the fourth quarter. As well, milder than normal weather during the fourth quarter significantly reduced light heating oil and heavy fuel oil consumption.

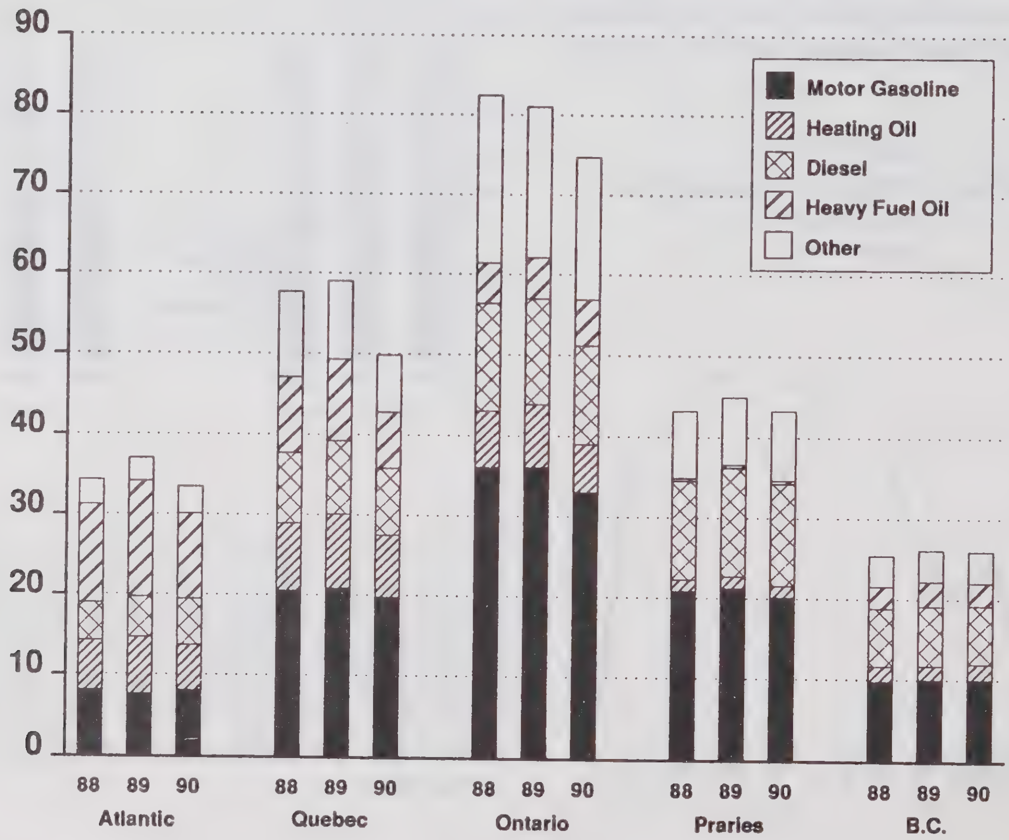
Actual sales (before seasonal adjustment) of petroleum products during the fourth quarter fell 9% to 227 000 m^3/d compared with a year earlier. Consumption of motor gasoline, which represented about 40% of total product demand, was down by 5% to 91 000 m^3/d. Diesel fuel oil declined by 4% to 46 000 m^3/d. Decreases of 17% and 20% to 23 000 m^3/d and 27 000 m^3/d were recorded in heating and heavy fuel oils, respectively. Other petroleum products, which includes petrochemical feedstocks, liquified petroleum gases, jet fuels, asphalts and lubes, experienced a 7% year over year decline to 41 000 m^3/d

With the exception of the Atlantic region which recorded a fourth quarter year-over-year growth of 6% in motor gasoline and 13% in diesel oil sales, all other regions registered declines. Motor gasoline sales in Quebec and the Prairies fell by about 5% each to 20 000 m^3/d. Sales in Ontario fell by 9% to 33 000 m3/d. Ontario and the Prairies, the largest users of diesel fuel oil, recorded sales of about 12 000 m^3/d each, a drop of 6% and 5%, respectively.

Milder weather in central and eastern Canada affected demand for both light and heavy fuel oils. Heating oil sales tumbled in the Atlantic region and Ontario by 20% and 25%, respectively, to about 6 000 m^3/d each. Sales in Quebec fell 16% to 8 000 m^3/d. In contrast, British Columbia, which experienced colder weather, saw an increase in consumption of almost 18% to 2 000 m^3/d.

Heavy fuel oil sales in the Atlantic region and Quebec

Figure 1.2.2
Regional Petroleum Product Sales
(Fourth Quarter)
000 m^3/d



declined by about 26% and 30% to 11 000 m^3/d and 7 000 m^3/d, respectively. Sales in Ontario increased 12% to 6 000 m^3/d. This increase, for the most part, was the result of electrical generating utilities building their heavy fuel oil inventories for the winter season.

Demand for other products dropped by almost 6% to 18 000 m^3/d in Ontario, the largest consumer. Quebec recorded a 28% decline to 7 000 m^3/d.

1.3 Heavy Fuel Oil Switching Capability

The following is an excerpt from a report entitled "Heavy Fuel Oil Switching Capability", detailing the results of a recent survey conducted by the **Energy Supplies Allocation Board.** The report provides analyses on the capability of industries and utilities to switch from heavy fuel oil to alternative fuels such as natural gas, coal and electricty.

Further information or copies of the report may be obtained by phoning (613) 992-8762 or (613) 992-0608.

Summary

The purpose of the survey was to update information on the capability of switching from heavy fuel oil to alternative fuels in the event of an oil supply crisis. The survey was initiated, following events in early August in the Persian Gulf, to assess the potential for reducing heavy fuel oil demand in a crisis and to fulfil Canada's information commitments to the International Energy Agency.

Approximately 500 questionnaires were sent to major users of heavy fuel oil in manufacturing, mining, electrical generation and institutions. Over 76% responded representing about 18 000 m^3/d heavy fuel oil consumption. In relation to 1990's estimated heavy fuel oil demand of 27 000 m^3/d, this figure represents a market coverage of 67% of the heavy fuel oil market in Canada.

Heavy fuel oil switching capability to alternative fuels was estimated, on a yearly basis, to be about 7 000 m^3/d or 25% of heavy fuel oil demand in Canada.

Switching capability of 5 000 m^3/d was found in the Atlantic region followed by Quebec and Ontario with about 1 000 m^3/d and 700 m^3/d, respectively. However, this also included switching to other oil products such as light fuel oil and diesel oil. When these fuels are removed as alternatives, the off-oil switching capability to other non-oil fuels becomes about 3 000 m^3/d or 9% of the estimated heavy fuel oil demand in Canada for 1990. Of this, over 66% or 2 000 m^3/d is potentially switchable to natural gas. As almost all of the heavy fuel oil switching capability to light fuel oil and diesel oil is found in the generation of electricity in the Atlantic region, the off-oil switching capability is reduced to 500 m^3/d in the Atlantic region, putting it in third place behind Quebec and Ontario. The off-oil switching capability in Quebec and Ontario remain unchanged.

On a short term basis with a lead time of 30 days, the switching capability in the first quarter 1991 is about 8 000 m^3/d. This figure is reduced to 3 000 m^3/d when oil products are excluded from the alternative fuels. Similar results are recorded for the second and third quarters of 1991.

On a national basis, the average 3 000 m^3/d switching capability represents approximately 1% of total product demand.

On a sectoral basis, off-oil switching capability is found principally in the pulp and paper, smelting and refining industries.

However, it should be noted that the switching capability figures cited represent the potential to switch. Actual switching would depend upon whether additional supplies of the alternative fuel, primarily natural gas, could be made available. In the winter months when the demand for natural gas peaks and the distribution is constrained, it is not likely that much switching would be possible.

Consequently, in an oil supply crisis, it is not expected that switching from heavy fuel oil to alternative fuels would be very effective in reducing the general level of demand required to respond to a supply shortfall.

2. Drilling and Exploration Activity.

- *Surplus capacity in the drilling industry continued through 1990 although rig utilization increased from the year before.*

- *Despite stronger oil prices brought on by the Persian Gulf crisis, producers favoured natural gas exploration.*

- *A modest increase in drilling activity is forecast for 1991, although the industry is expected to continue to be hampered by uncertainty.*

The drilling industry recorded some improvement in 1990. According to the Canadian Association of Oil Drilling Contractors (CAODC), 35% or 171 of 487 available rigs were reported active in western Canada. This compares with only 30% or 154 of 512 rigs recorded the year before - one of the worst years on record for the industry.

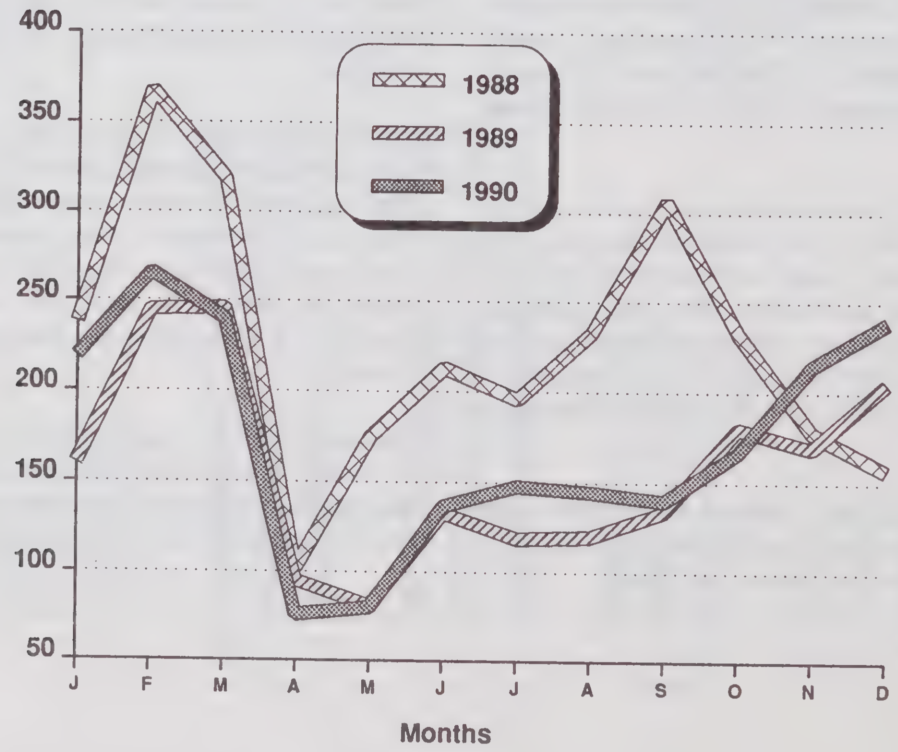
Despite continuing surplus capacity, the process of consolidation and rationalization which has characterized the equipment side of the industry over the last several years, has apparently slowed. The number of available rigs decreased from 528 in January of 1989 to 498 in December. By the end of 1990 only 6 more rigs had been eliminated.

A hoped for 15% increase in drilling activity over the year was only partially realized. However, during the fourth quarter of 1990 drilling activity exceeded expectations as the industry began to respond to higher crude oil prices following the onset of the Persian Gulf crisis.

Over the fourth quarter, 42% or 201 of 484 available rigs were reported active, compared with 37% or 183 of 498 rigs in the fourth quarter of 1989. As illustrated in figure 2.1, activity in November and December recorded a marked improvement over the same period last year.

There were 8% more oil and gas wells completed in 1990, this following a sharp 40% loss in 1989. By the

Figure 2.1
Drilling Activity in Western Canada
(number of active rigs)



end of the year, 5881 wells (including dry wells) had been completed with the number of metres drilled up 10% to 6.9 million. Fourth-quarter well completions also increased, up 8% from the year before.

Exploratory well completions increased 19% to 2773. As illustrated in figure 2.2 natural gas remained the favoured target of producers largely because of an anticipated expansion in the export market. While oil well completions rose 9% to 476, gas completions jumped 19% to 1157 with most of the increase recorded in northeast British Columbia and the Alberta foothills region.

On the other hand, development well completions, as illustrated in figure 2.3, increased a modest 3% to 3108. While gas completions fell 9% to 1226, oil completions recorded a 13% increase to 1449 primarily on the strength of a near doubling of activity in Saskatchewan.

For 1991, the CAODC forecasts 38% (or 182) of 480 available rigs operating with emphasis still on natural gas augmented by the search for oil to replace dwindling supplies of light crude. Despite this forecasted increase, the industry is expected to continue to be hampered by price uncertainty and modest activity.

Nevertheless, the CAODC suggests that the financial position of producers may have improved somewhat as most of the earning from higher crude oil prices in the fourth quarter were directed to industry debt reduction. As well, the association suggests that reduced debt combined with improved cash flow, lower interest rates and higher exports of crude oil and gas could further strengthen the financial position of producers over the year.

The CAODC forecasts 56% or 270 of 480 rigs active during the first quarter of 1991. Activity could prove somewhat higher as both January and early February drilling exceeded expectations. This relatively high level of activity is expected to continue through to spring break-up when weather conditions and road bans restrict field activity.

Figure 2.2
Exploratory Well Completions
thousands of wells

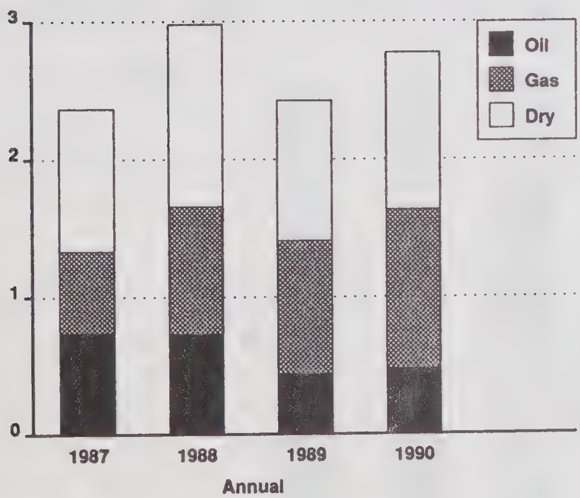
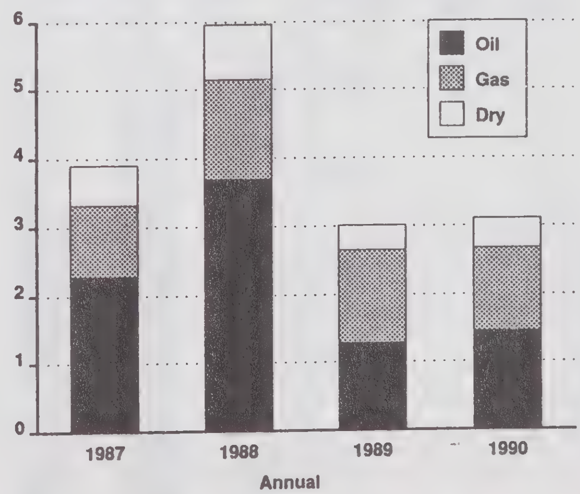


Figure 2.3
Development Well Completions
thousands of wells



3. Crude Oil Supply

- *Domestic crude oil and equivalent production in 1990 continued to lag behind 1989, although fourth quarter production recorded a moderate recovery.*

- *Crude oil imports rose sharply in the fourth quarter reflecting in part a switchover to foreign crudes by Montreal refiners.*

- *For the year as a whole, imports increased by 9 000 m3/d with most of the increase in Quebec.*

3.1 Total Crude Oil Supply

Total supply of crude oil and equivalent in 1990 averaged 356 000 m^3/d compared with 347 000 m^3/d in the previous year. Of this volume, domestic supply (including production from Ontario, recycled diluent, surplus Newgrade supply re-injected into the Interprovincial Pipe Line and inventory change) averaged 269 000 m^3/d. Gross imports at 86 000 m^3/d accounted for the remainder. The equivalent of 29% or 104 000 m^3/d of this supply was delivered to the export market.

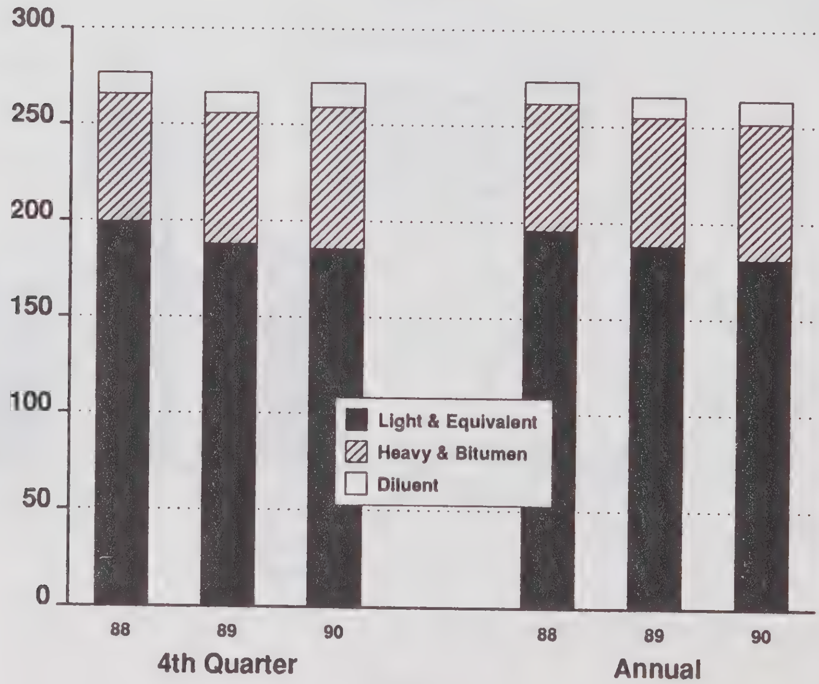
Fourth quarter supply averaged 369 000 m3/d, compared to 342 000 m^3/d a year earlier. Domestic supply, on the strength of higher light and heavy production, increased 4% to 277 000 m^3/d, while imports rose 21% to 92 000 m^3/d.

For further supply and disposition details see Appendix I and II.

3.2 Domestic Crude Production

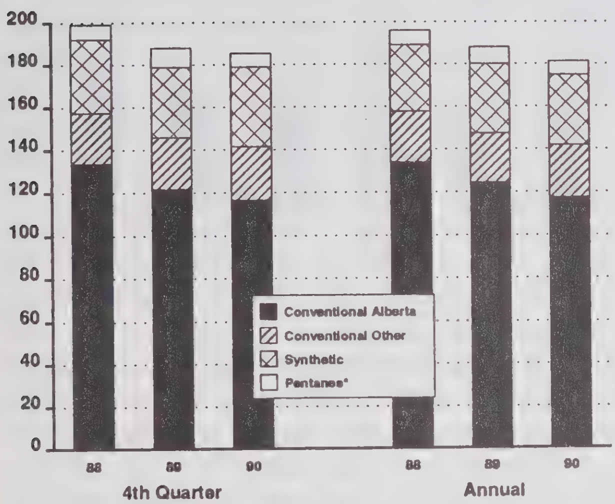
Total domestic production of crude oil and equivalent during 1990 averaged 264 000 m^3/d. As a result of falling conventional light crude output, total production dropped for the second consecutive year, albeit at a slower rate. The drop may have been tempered somewhat by producer 'surge' production in response to higher prices due to Persian Gulf crisis. In fact, fourth-quarter production at 272 000 m^3/d was nearly 2% higher than the previous year.

Figure 3.2.1
Total Crude Oil and Equivalent Production
000 m^3/d



Over 1990, conventional light crude production fell 4% to 142 000 m^3/d. Most of the drop was recorded in Alberta where production fell 6% to 117 000 m^3/d. However, synthetic output from Alberta's two commercial oil sands plants, Syncrude and Suncor, recorded some improvement. Although combined production at 33 000 m^3/d was only slightly higher than the year before, fourth quarter output increased to 37 000 m^3/d as both plants operated at near capacity. Production reached a record breaking average of 40 000 m^3/d in October.

Figure 3.2.2
Light and Equivalent Production
000 m^3/d

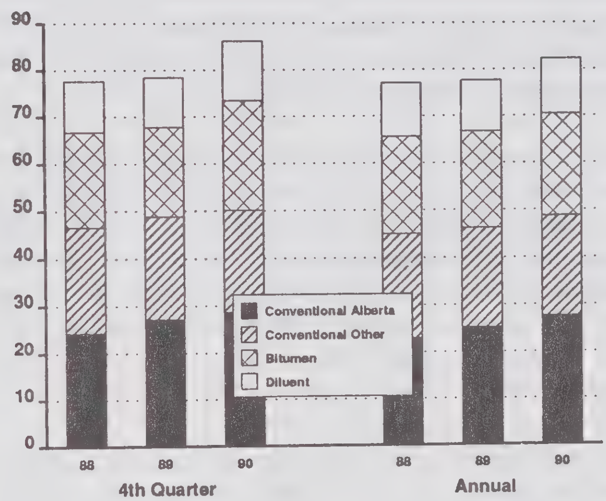


** excludes diluent*

The supply of pentanes plus and condensate, held at about 18 000 m^3/d. Thus, with falling conventional production, higher synthetic output and a steady supply of pentanes plus, net production (less diluent) of total light crude and equivalent dropped 4% the year before to 181 000 m^3/d. Fourth-quarter production at 186 000 m^3/d was marginally lower than a year earlier.

As conventional light crude output continued its slide, total unblended heavy crude production expanded. While bitumen production remained relatively unchanged at 21 000 m^3/d, conventional production of heavy crude rose 5% to 49 000 m^3/d, with most of the increase the result of improved enhanced oil recovery techniques and horizontal drilling programs. In the fourth quarter, total production jumped 9% from the year before to about 74 000 m^3/d. Production remained high, despite the end of the asphalt season, with surplus production absorbed into inventory.

Figure 3.2.3
Heavy Crude Oil Production
000 m^3/d



Based on National Energy Board estimates, crude oil and equivalent productive capacity in 1991 will average to 265 000 m^3/d, compared to 268 000 m^3/d (4 000 m^3/d of which was shut-in) in 1990. Light conventional crude production is expected to continue to slide with conventional heavy and bitumen production posting modest gains. First quarter 1991 production is estimated at 268 000 m^3/d slightly higher than a year earlier.

3.3 Crude Oil Imports

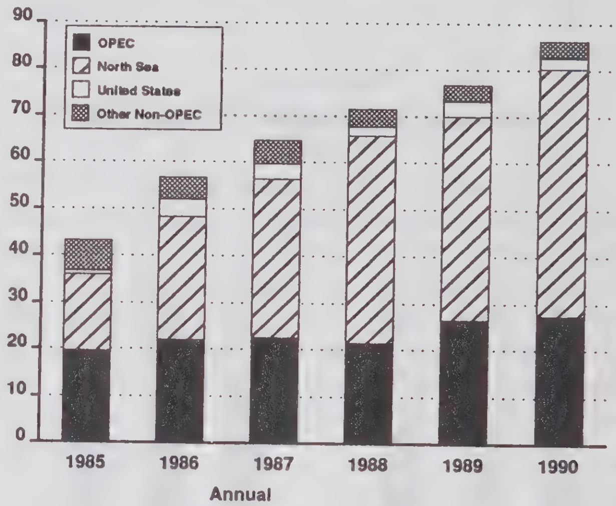
Foreign crude oil deliveries to refineries in eastern Canada exceeded 92 000 m^3/d during the fourth quarter of 1990. This amounted to a 16 000 m^3/d increase over the same period in 1989. Imports made up 36% of total crude oil receipts in Canada. Regionally, foreign crudes met virtually all the feedstock requirements of the refineries in the Atlantic and almost 90% of those in Quebec. In Ontario, where imported volumes have traditionally been small, they accounted for less than 2% of receipts.

All of the rise in imports in the fourth quarter occurred in Quebec, there being no change in the Atlantic and a decline in Ontario. About half of the 18 000 m^3/d increase in Quebec compensated for the reduction in shipments of domestic crude oil to the two Montreal refineries. Domestic crude deliveries dropped from an average of about 14 000 m^3/d during the first three quarters of 1990 to 5 000 m^3/d in the fourth quarter.

For the year as a whole, imports averaged 86 000 m^3/d in 1990, up 9 000 m^3/d from 1989. In the Atlantic, virtually all of the 2 000 m^3/d increase to 48 000 m^3/d translated into higher exports of refined products. The 9 000 m^3/d rise to 35 000 m^3/d in Quebec largely went towards improving the region's net product trade balance. In Ontario, imports, declined by almost 2 000 m^3/d to under 3 000 m^3/d.

North Sea crudes accounted for all the increase in foreign receipts, rising 10 000 m^3/d from the previous year to comprise 61% of total imports. This reflected developments in Quebec, whose refineries have traditionally relied on North Sea oil when importing. OPEC deliveries, mostly to Atlantic refiners, remained steady, accounting for 32% of total imports in 1990. Saudi Arabia and Nigeria continued to be the dominant OPEC suppliers.

Figure 3.3.1
Imports of Crude Oil by Source
000 m3/d



According to a National Energy Board survey of refiners' intentions completed in early January, imports in 1991 are expected to be at least as high as they were in 1990 and will likely be some 3 to 4 000 m^3/d higher, in light of the reduced use of the Sarnia-Montreal pipeline extension during the year. Most of the incremental imports should come from the North Sea, judging from the past preferences of the refiners.

4. Crude Oil Disposition

- *Refinery crude oil receipts rose by 3% in 1990, despite falling domestic demand for refined products. The increase in receipts helped generate a higher trade surplus in refined products.*

- *Exports increased modestly as a result of declining domestic demand and price competitiveness of Canadian crudes particularly during the fourth quarter.*

4.1 Canadian Refinery Crude Oil Receipts

Domestic refiners sustained their high level of demand for crude oil during the fourth quarter of 1990, notwithstanding the sharp downturn in domestic sales of refined products during this period. Averaging 259 000 m^3/d, crude oil receipts were 18 000 m^3/d or 8% higher than in the corresponding period of 1989. About three quarters of the increase pertained to higher crude runs and the remainder to the fact that crude oil inventories were built during the quarter rather than being drawn down as in the previous year. Although all regions recorded gains, about half the total increase was recorded in Quebec where crude oil deliveries rose by 22%. With this increase came a significant improvement in Quebec's net trade position in refined products, reflecting in part an addition to capacity at one of the region's refineries early in 1990.

Refinery receipts of domestic crude oil grew by 2 000 m^3/d to 167 000 m^3/d. Domestic crudes comprised 65% of total receipts during the quarter. Nevertheless, foreign crudes accounted for almost 90% of the incremental receipts. Imports rose by 16 000 m^3/d to 92 000 m^3/d, the highest quarterly average since the early eighties. Quebec refiners, opting for offshore crudes, increased these receipts (predominantly from the North Sea) by close to 18 000 m^3/d; while dropping their demand for domestic crude by 9 000 m^3/d to a mere 5 000 m^3/d. Canadian crudes now made up only about 10% of the region's total receipts versus a 30% share during the first nine months of the year. With throughput on the Sarnia-Montreal pipeline falling, to the point where the pipeline was operating at only about 10% of its capacity, the issue of whether and when the pipeline should be shut down or reversed came to the forefront.

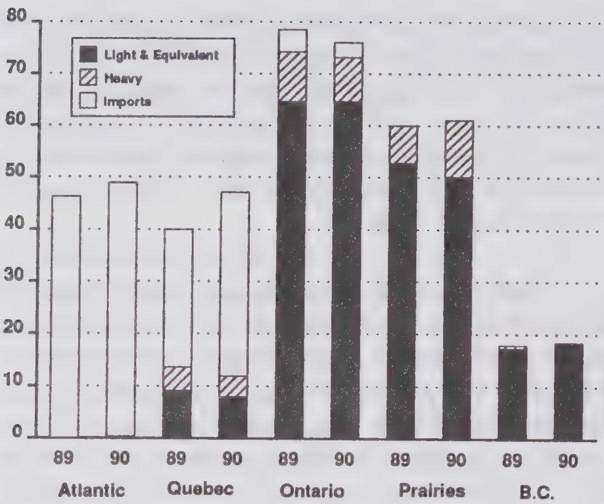
For the year 1990, crude oil receipts averaged 251 000 m^3/d, up over 8 000 m^3/d, or 3%, from 1989. Receipts of domestic crude oil remained relatively steady in the 165 000 m^3/d range, with lower demand in Quebec and Ontario offsetting increases in western Canada. Imports into eastern Canada, on the other hand, rose by 9 000 m^3/d to 86 000 m^3/d.

The overall rise in crude oil demand occurred despite falling product consumption in Canada. Part of the increase went towards a build in crude oil and product inventories over the year. However, it helped generate a 10 000 m^3/d improvement in Canada's net trade position in refined products (i.e. from a surplus of about 6 000 m^3/d in 1989 to one of 16 000 m^3/d in 1990). The higher surplus manifested itself mainly through an increase in product exports from the Atlantic region, and a drop in product imports into Quebec. That all the incremental crude oil receipts happened to be met from imports, follows from the fact that Atlantic refiners are almost entirely dependent on foreign crude feedstocks, and Quebec refiners increasingly so.

In the Atlantic, receipts averaged close to 49 000 m^3/d, about 2 000 m^3/d higher than in 1989. Apart from a few transhipments of domestic heavy crude oil, Atlantic refiners continued to process only foreign feedstocks. Virtually all the increase in crude receipts translated into increased exports of refined products.

A significant increase in crude oil demand occurred in Quebec where receipts rose 7 000 m^3/d to 48 000 m^3/d. Despite the abrupt downturn in domestic crude oil receipts during the fourth quarter, these deliveries had, up until then, averaged a little higher than in 1989. Consequently, annual figures show the demand for domestic crude oil declining by less than 2 000 m^3/d to 13 000 m^3/d, while imports rose by a third to 35 000 m^3/d.

Figure 4.1
Refinery Crude Oil Receipts
by Region
000 m^3/d



In Ontario, total receipts declined by almost 3 000 m^3/d to 79 000 m^3/d. The decline was split between domestic and foreign crudes, with domestic receipts declining to 76 000 m^3/d, and imports to below 3 000 m^3/d. All the decline occurred during the second quarter when a relatively large number of prolonged refinery turnarounds sharply curtailed crude oil demand. Over the year, an increase in product transfers from Quebec and the Prairies helped meet the demand for refined products in the region.

A rise in throughput at the Newgrade heavy oil upgrader helped push Prairie receipts up by about 1 000 m^3/d to 64 000 m^3/d. The upgrader performed relatively well in 1990 despite being shut down early in the year for extensive repairs following a power outage, and then again in June for a major plant turnaround. Heavy crude deliveries, in fact, climbed by almost 4 000 m^3/d from the year before, largely to meet the increased feedstock requirements of the upgrader.

Prairie demand for light crude oil, on the other hand, fell by almost 3 000 m^3/d. In part this was because the refinery adjacent to the Newgrade upgrader no longer had to substitute conventional light supply to compensate for shortfalls in Newgrade production, as was often the case in 1989 when commissioning problems brought the upgrader's operations to a halt on a number of occasions, including an extended shutdown in the latter half of the year. Demand for light crude oil was also reduced in 1990 when an explosion and fire sharply curtailed throughput at a major refinery in the Edmonton area during the summer.

In British Columbia, crude deliveries rose marginally, averaging close to 19 000 m^3/d over the year. Not included in this volume are some 5 000 m^3/d of partially processed oil transferred from Edmonton to Vancouver area refineries.

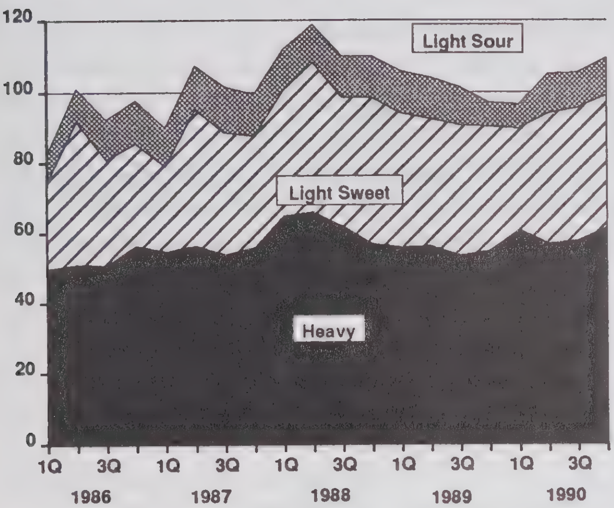
On the basis of a survey of refiners' intentions completed by the NEB in early January, the total volume of crude oil demanded by domestic refiners is expected to decline by 3 or 4% to around 242 000 m^3/d in 1991. Refiners are anticipating lower refined product sales and fewer product exports during the recession. Declines in crude oil demand are indicated in all regions except Ontario where there may be a marginal recovery.

Since it was conducted prior to the March announcement of the shutdown of the Sarnia-Montreal extension, the survey likely underestimates the expected level of imports, specifically into Quebec. Adjusting the data to reflect the impact of the pipeline closure raises imports to an average of about 90 000 m^3/d for the year, while commensurately lowering domestic crude oil receipts to about 152 000 m^3/d. Moreover, because Ontario refiners were planning to rely almost exclusively on domestic crude feedstocks in any event, the surplus in domestic crude supply effected by the closure will probably end up being entirely diverted to the export market.

4.2 Crude Oil Exports

Crude oil and equivalent exports for 1990 averaged 104 000 m^3/d. Although on the decline since 1988, the result of shortfalls in conventional light crude production, exports recorded a modest 1% increase over the previous year. Fourth quarter exports averaged 110 000 m^3/d, almost 10% more than a year earlier.

Figure 4.2.1
Crude Oil Exports
000 m³/d



The increase in exports, particularly over the last half of the year, was the result of a number of factors. Most importantly, as discussed in section 8.3, was the price competitiveness of Canadian crudes delivered into the key Chicago refining area. Over the third and fourth quarters, producers were forced to discount export prices as a result of increased supply coming from higher domestic production, and the drop in demand for domestic feedstocks in Quebec.

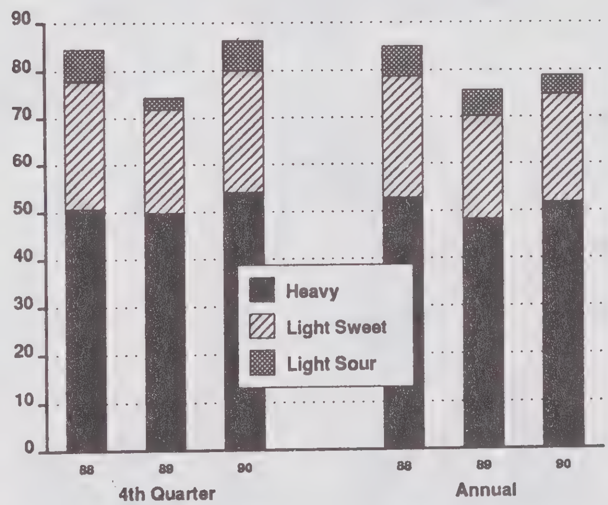
Exports represented 40% of domestic production (72% of blended heavy supply and 25% of net light and equivalent), compared with 38% last year. Heavy crude exports, supported in part by a modest rise in production, increased 7% to 60 000 m^3/d. Exports of light rose 5% to 44 000 m^3/d with increased shipments of synthetic crude, offsetting a decline in conventional light crude.

As illustrated in Appendix III, most Canadian crude oil exports are delivered to the United States with typically three quarters of this volume shipped to U.S. PAD District II (the Minneapolis/St.Paul and Chicago refining areas). The remainder is shipped offshore via the ports of Vancouver and Montreal.

In 1990, small volumes of mainly heavy crude were shipped offshore through Vancouver (via the Trans Mountain Pipe Line and Westridge Marine Terminal) to various Pacific Rim destinations, most notably South Korea. No offshore exports were reported shipped through the port of Montreal.

As illustrated in figure 4.2.2., PAD District II receipts increased 4% to 79 000 m^3/d. However, fourth quarter deliveries, representing about 44% of the district's import requirements, increased 15% from a year earlier to 85 000 m^3/d. While deliveries of heavy crude increased 9% to 54 000 m^3/d, light crudes jumped 30% to 31 000 m^3/d.

Figure 4.2.2
U.S. PAD District II Receipts
000 m³/d



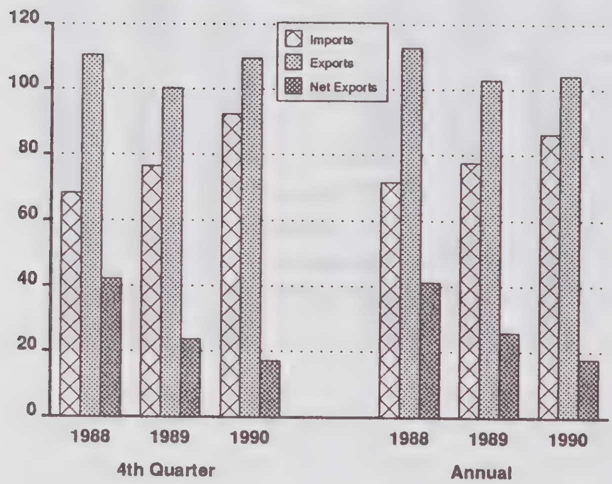
While U.S. PAD District II, particularly the Chicago refining area, recorded the largest increase in Canadian crude deliveries, all other PAD Districts adjusted their crude take marginally. Deliveries to Canada's second largest export market, PAD District IV (the Montana and Wyoming refining area) held at about 12 000 m^3/d.

While Canadian exports to the United States peaked in 1988, U.S. demand for imported crude has continued to rise although at a slower rate in 1990 than previous years.

According to the U.S. Department of Energy, imports in 1990 averaged 932 000 m^3/d compared with 922 000 m^3/d in 1989. Canada supplied about 11% of this volume compared with 10% in 1989. Over the year Canada ranked the fifth largest U.S. supplier of imported crude behind Saudi Arabia, Nigeria, Mexico and Venezuela and followed by Iraq.

As a result of rising imports, Canada's net crude export position in 1990 declined. In fact, it has been falling for the last several years. As illustrated in figure 4.2.3, exports in 1990 exceeded imports by about 18 000 m^3/d compared with 26 000 m^3/d in 1989. Although crude exports during the fourth quarter increased by 9 000 m^3/d, Canada's net export position did not, as imports into eastern Canada jumped by nearly 16 000 m^3/d compared with a year earlier.

Figure 4.2.3
Net Crude Oil Export Position
000 m^3/d



Export demand for Canadian crude oil and equivalent is expected to remain strong but deliveries could be affected by the state of the American economy, the postwar glut of heavy crude and a slide in crude oil prices.

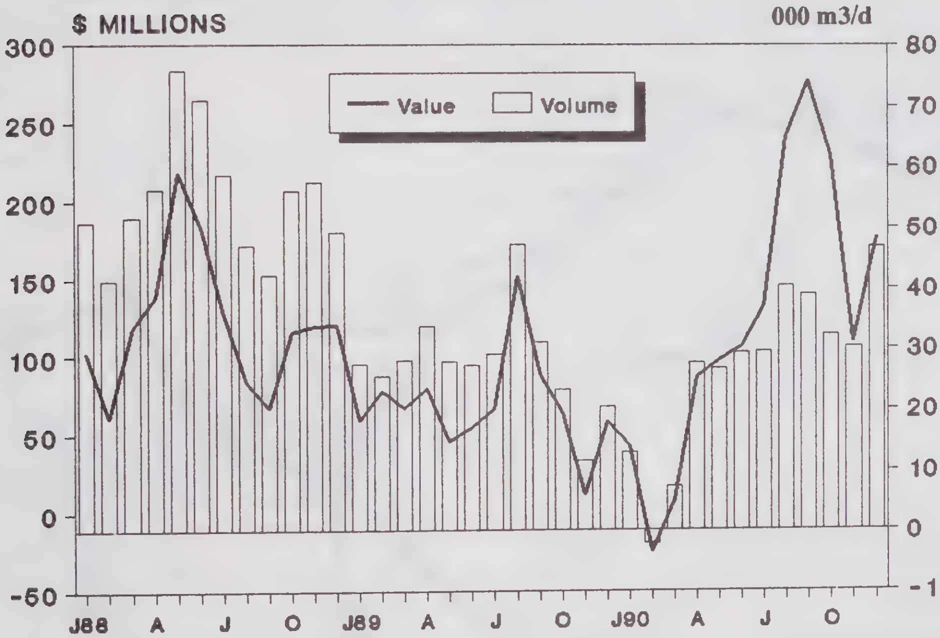
4.3 Net Oil Trade

According to Customs-based Trade of Canada figures, the value of Canada's trade surplus in oil in 1990 rose by over $400 million from the year before to approach $1.3 billion. All the gains were confined to trade in refined products, given that a substantial rise in crude oil imports, compared to only a marginal increase in exports, precluded an increase in the crude oil surplus. The rise in the overall oil surplus marked an abrupt reversal of the downward trend observed in the previous two years. Figure 4.3.1 traces the course of the oil trade surplus over the last three years, in both value and volume terms.

Since oil prices were low and falling during most of 1988, the comparatively high surplus that year came from high net exports of both crude oil and refined products. However, a significant drop in domestic crude oil production and higher product demand combined to cut the surplus almost in half in 1989. Imports of both crude oil and refined products rose, while exports fell. Nevertheless, the decline in the surplus was mitigated by the higher level of oil prices in 1989. This follows from the fact that, as a net oil exporter, Canada gains more than it loses from a rise in oil prices.

Canada's net trade position deteriorated rather sharply in the latter half of 1989 before reaching a low point early in 1990. The small trade deficit in February 1990 resulted, for the most part, from the combination of a sharp drop in output at Syncrude, which curtailed crude oil exports while raising imports into central Canada; and a sizeable crude oil inventory build by an Atlantic refiner which further boosted imports. Over the rest of the year however, Canada was once again running a surplus in oil trade. Although Canadian crude oil production continued to decline in 1990, which would tend to lower the surplus, the decline was small relative to that of 1989. Moreover, the recession, higher oil prices, and milder weather caused an even greater decline in the domestic demand for oil so that the volumetric surplus actually ended up being higher than in the previous year. More importantly, the increase in last year's surplus was largely price-generated, reflecting the high oil prices that ensued in the latter half of the year from the conflict in the Persian Gulf.

Figure 4.3.1
Net Oil Trade
(Value vs Volume)



5. Pipelines

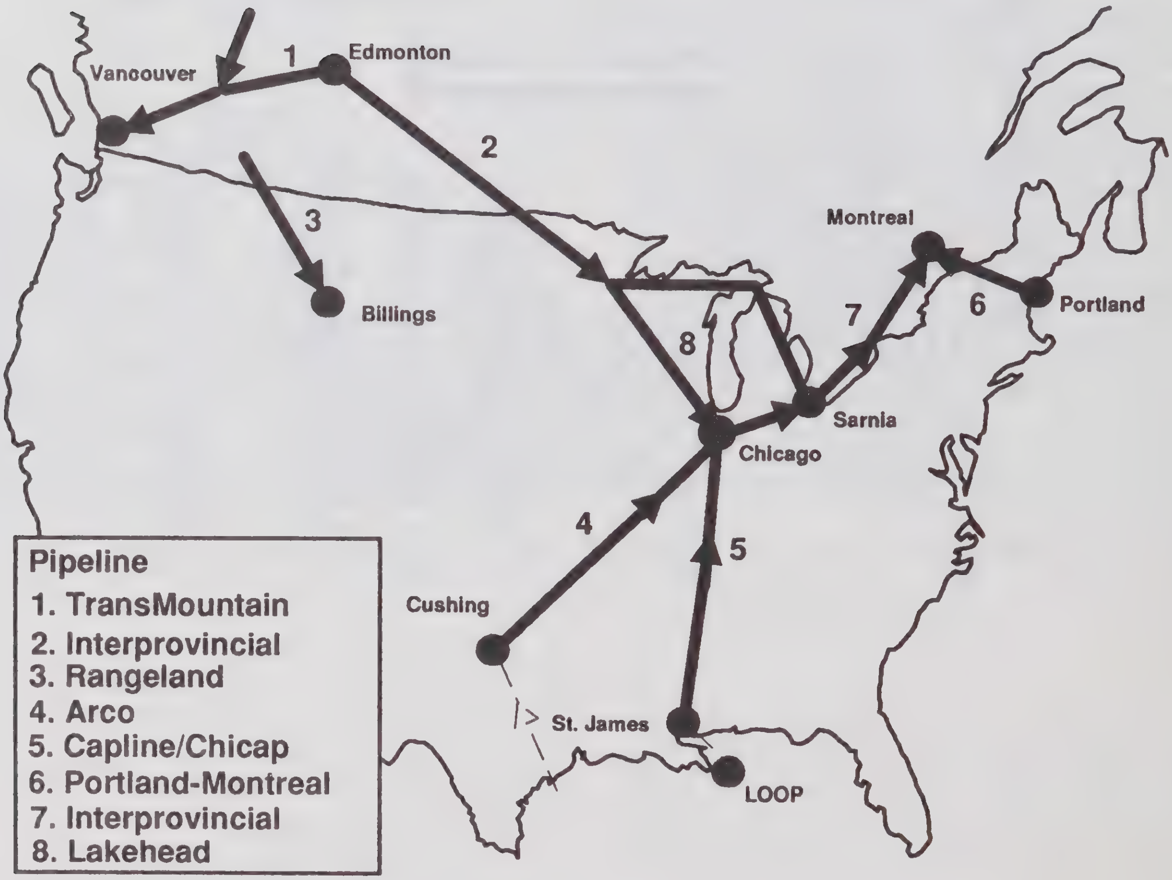
- *Total deliveries on the two main trunk lines were virtually unchanged compared to the same period last year.*

- *The Interprovincial Pipe Line has proposed the closure of the Sarnia to Montreal extension.*

Western Canadian crude oil is, for the most part, delivered to markets through a network of pipelines. A map illustrating major crude oil pipelines in North America is shown below.

The Trans Mountain Pipe Line and the Interprovincial Pipe Line originate in Edmonton, where most Canadian crude oil is gathered. The Rangeland pipeline supplies U.S. refiners south of the Prairie provinces. The selected American pipelines shown on the map illustrate the supply alternatives for our main export market. Chicago is predominantly supplied with U.S. domestic crudes from Cushing, Oklahoma, with foreign crudes through the U.S. Gulf and with Canadian crudes via the Interprovincial Pipe Line.

Figure 5.
Major Crude Oil Pipelines
In North America



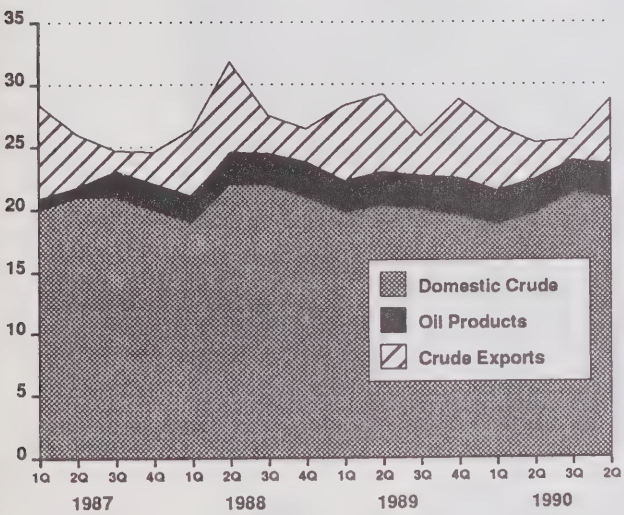
5.1 Trans Mountain Pipe Line Deliveries

During the fourth quarter of 1990, Trans Mountain Pipe Line (TMPL) throughput averaged 29 000 m^3/d, up approximately 3 000 m^3/d from the previous quarter and virtually unchanged compared with the same quarter last year.

Total deliveries of crude oil to refineries in British Columbia during the fourth quarter averaged 16 000 m^3/d, representing an increase of approximately 2 000 m^3/d over the fourth quarter of 1989. Deliveries of semi-refined products decreased by 1 000 m^3/d to 5 000 m^3/d. Deliveries of refined products from Edmonton to Kamloops remained stable at 3 000 m^3/d.

Crude oil deliveries for export by tanker from the Westridge marine terminal averaged 4 000 m^3/d, which was 500 m^3/d more than a year ago. Pipeline exports from Sumas to the Pugent Sound area averaged 1 000 m^3/d during the quarter, representing a decrease of 1 000 m^3/d from last year.

Figure 5.1
Trans Mountain Deliveries
000 m^3/d



TMPL is now seeking regulatory approval as the next step of an offshore oil terminal and pipeline project in Washington State. The company expects to spend some $10 million during this process, mostly on research addressing the issues of pipeline construction and safety. TMPL plans to make application to state regulators by November of 1991 and expects a decision within a year.

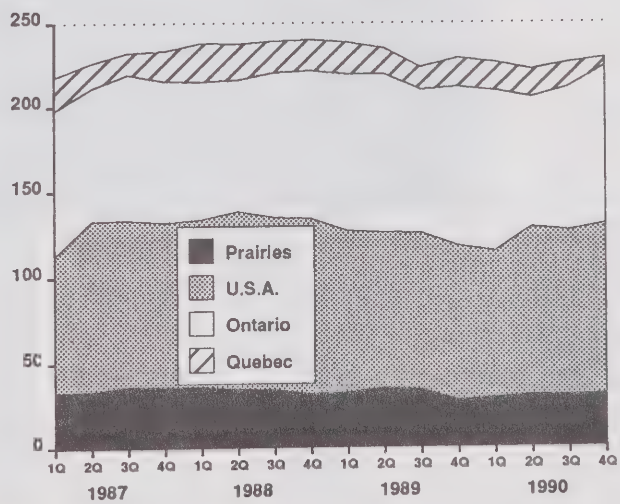
5.2 Interprovincial Pipe Line Deliveries

The Interprovincial Pipe Line (IPL) system consists of two connected segments, the first one is in Canada and is commonly referred to as IPL while the second, called "Lakehead", serves American markets in the Great Lakes area.

Total IPL and Lakehead deliveries of crude oil and other hydrocarbons, including petroleum products and natural gas liquids, during the fourth quarter of 1990, averaged 229 000 m^3/d, up approximately 3 000 m^3/d from the previous quarter and equal to the same quarter one year ago.

Total deliveries of crude oil to Canadian refineries during the fourth quarter were 130 000 m^3/d, 9 000 m^3/d less than a year earlier and approximately the same as the third quarter. Deliveries to Canadian refineries represented 57% of total IPL throughput. Deliveries to the United States, at 99 000 m^3/d, were up 9 000 m^3/d from the same quarter the previous year.

Figure 5.2
Total IPL Deliveries
000 m^3/d



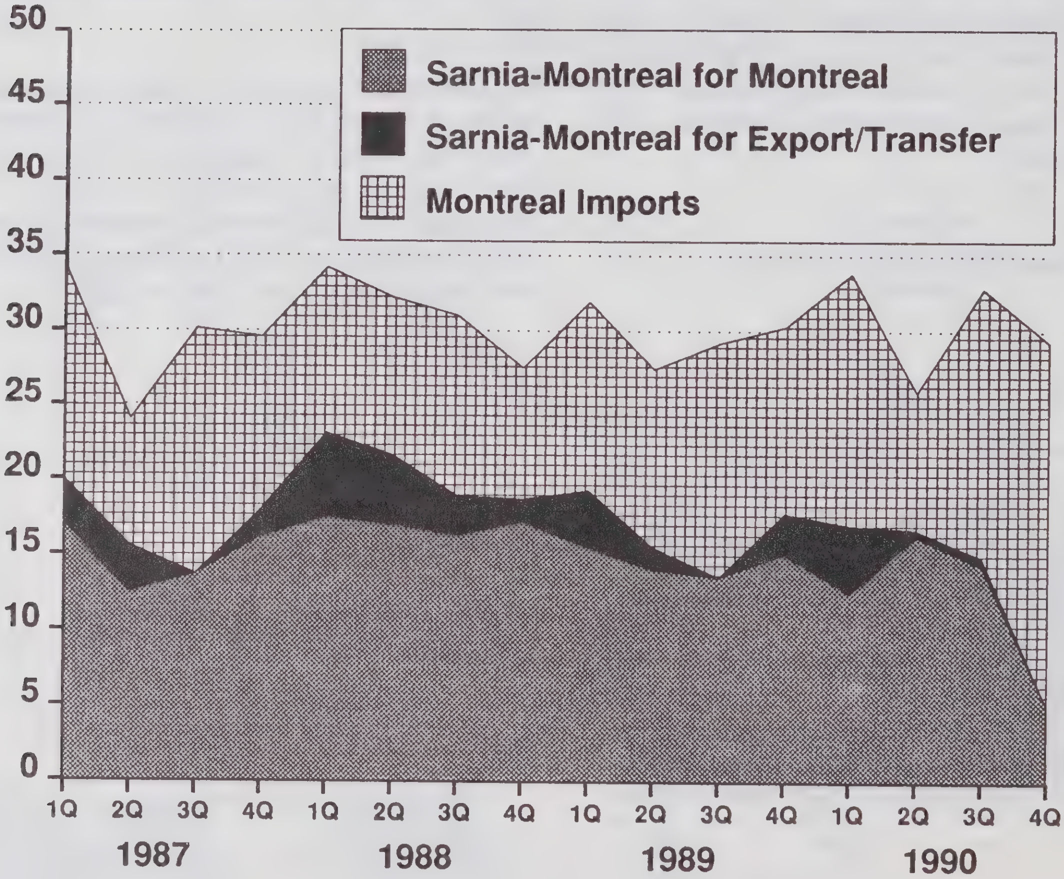
5.3 Pipelines to Montreal

Total deliveries of crude oil and equivalent (foreign and domestic) to Montreal refiners, during the fourth quarter of 1990, averaged about 29 000 m^3/d, up 1 000 m^3/d from the same quarter a year earlier.

Total domestic crude deliveries via the Sarnia-Montreal portion of the IPL system averaged 5 000 m^3/d, 10 000 m^3/d less than the year before, all for use by Montreal refineries. Foreign crudes, imported mainly through the Portland Pipe Line, averaged 24 000 m^3/d, up 11 000 m^3/d from the same period last year.

IPL announced on March 20, 1991 that the over 800 kilometre Sarnia to Montreal pipeline extension will be deactivated on April 25, 1991. However, the company is prepared to reactivate the line during the subsequent twelve months, if shipping demand warrants.

Figure 5.3
Deliveries to Montreal
000 m^3/d



6. Refinery Throughput and Utilization Rates

- *The national refinery utilization rate averaged about 85% in 1990. The utilization rate was the highest in Quebec and lowest in Ontario.*

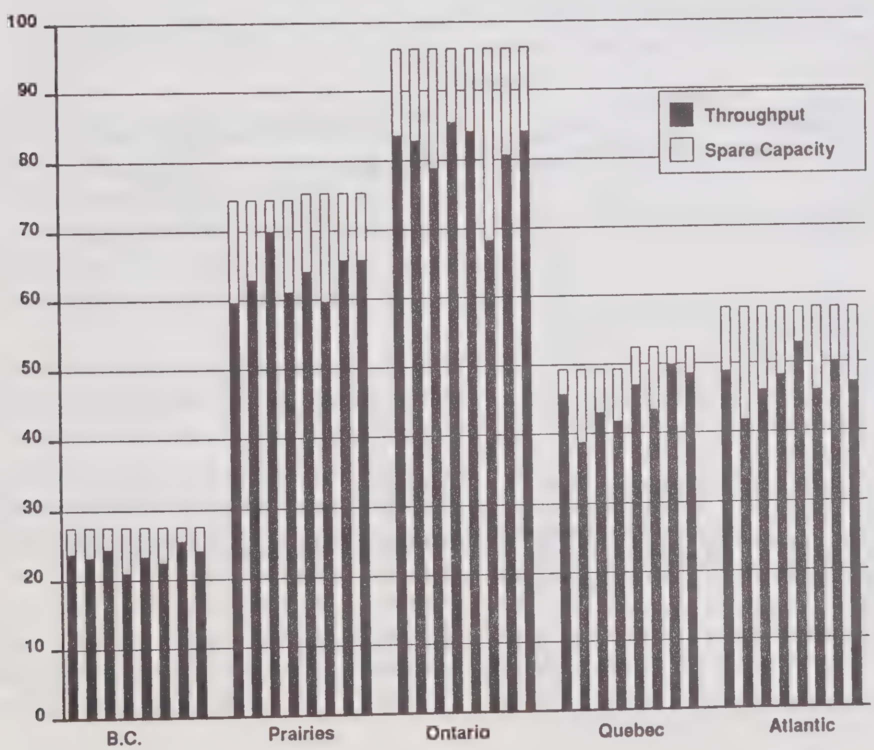
Refinery throughput will normally diverge from refinery crude oil receipts for two reasons. First, feedstocks other than crude oil are also charged in the refining process. Some of the 'other' feedstocks include gas plant butanes (used mostly by Prairie refineries) and partially processed oil (used mostly by B.C. refineries). During 1990, these 'other' receipts averaged 13 000 m^3/d or about 5% of total refinery throughput in Canada. Second, refinery throughput reflects changes in feedstock inventories. Other things being equal, an inventory drawdown will cause refinery throughput to exceed receipts - and vice versa in the case of an inventory build.

Over the year, crude oil inventories at the national level were built at a rate of 1 000 m^3/d.

Total throughput averaged 263 000 m^3/d, about 5 000 m^3/d higher than in 1989. With estimated Canadian refining capacity now up by about 4 000 m3/d to 310 000 m3/d, due to capacity expansions earlier in the year at refineries in Quebec and the Prairies, the level of throughput corresponded to a national refinery utilization rate of about 85%. The utilization rate was highest in Quebec where it reached 90%, and lowest in Ontario, at 82%. Figure 6.1 illustrates refinery throughputs and capacities by region from the first quarter of 1989.

Refinery throughput is likely to decline across all regions in 1991, in tandem with crude oil receipts. In British Columbia, refinery capacity will fall by almost 3 000 m^3/d when a refinery in northern B.C. is shut down in June. This should result in more refined products being supplied to this region from a sister refinery in Edmonton.

Figure 6.1
Refinery Utilization vs Capacity
(1st Quarter 1989 to 4th Quarter 1990)
000 m^3/d



7. Stocks

- *A slowing economy, higher prices due to the Persian Gulf crisis and relatively warm temperatures combined to restrain product demand and increase stocks .*

Primary stocks of crude oil and refined petroleum products closed 1990 at 14.9 million m^3, up 5% from a year earlier and 10% above the previous quarter. Crude oil stocks, accounting for 3.0 million m^3 of this total, were 13% higher than the previous year. Petroleum product stocks were up 3% to 11.9 million m^3.

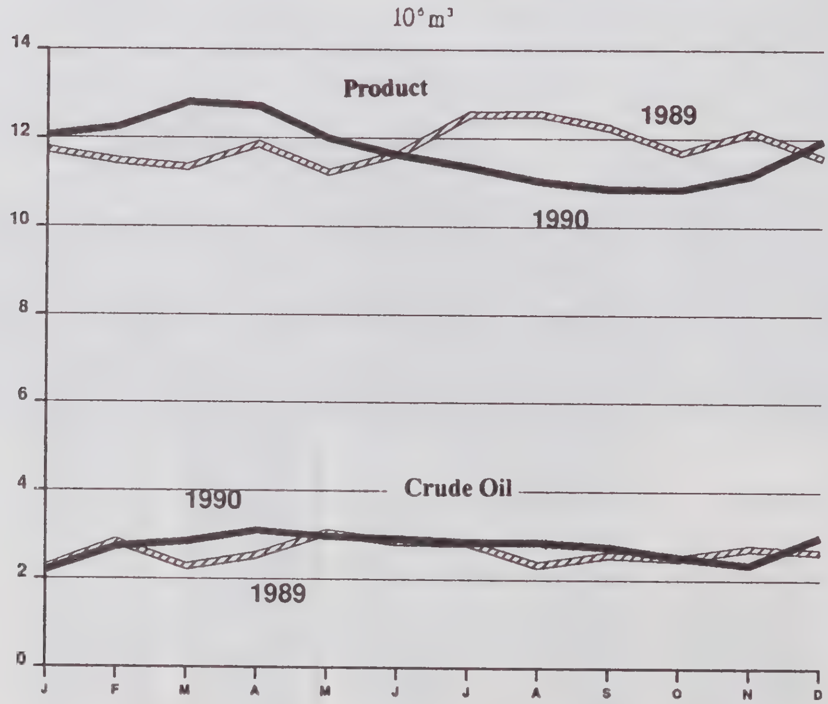
As illustrated in table 7.1, end-of-year stock changes were for the most part concentrated in Quebec where stocks of crude and products increased by nearly 23% compared to a year earlier. Much of this increase was related to fourth quarter supply and price concerns as a result of the Persian Gulf crisis.

Table 7.1
Closing Crude and Product Inventories
(End December)
000 m^3

	Crude			Products		
	1988	1989	1990	1988	1989	1990
Atlantic	808	1201	1246	1953	2133	2040
Quebec	918	513	745	2299	2453	2891
Ontario	508	575	620	3384	3487	3609
Prairies	257	271	275	2379	2421	2258
B.C.	74	92	106	1199	1077	1157
Canada	2565	2652	2992	11214	11571	11955

As illustrated in figure 7.1, stocks of crude oil remained within normal operating levels throughout 1990. A weak economy and relatively warm temperatures, particularly

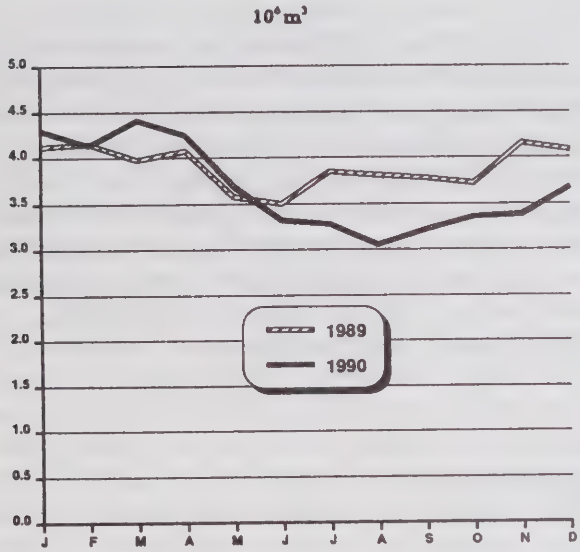
Figure 7.1
Crude Oil and Petroleum Product Stocks



during the latter half of 1990, held the level of petroleum product stocks near that of the year before.

Over the year, stocks of motor gasoline were well below the year before. Strong demand for gasoline during the peak June through August driving season kept supplies relatively low. However, demand abated with the end of summer driving season and with rising prices following the onset of the Persian Gulf crisis.

Figure 7.2
Motor Gasoline Stocks

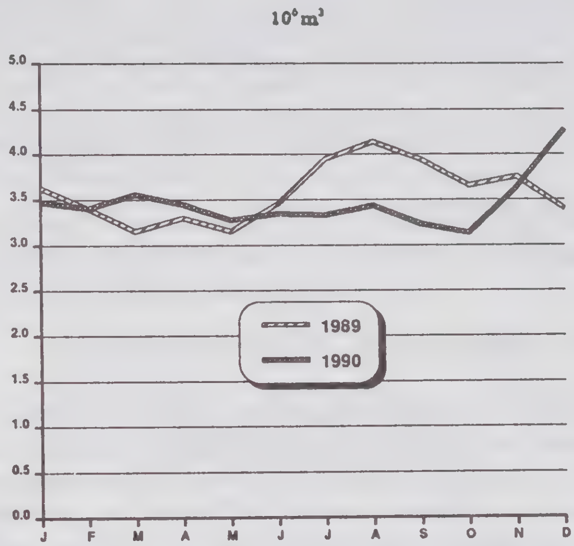


For most of 1990, stocks of distillate fuel oils were well below the year before. However, by late in the year stocks were above that of a year earlier when unseasonably cold weather resulted in high demand and falling inventories. By the end of December 1990, stocks reached a yearly high as warm weather reduced demand.

Warmer weather and lower industrial production caused stocks of residual fuel oil to remain high for most of the year. Over the fourth quarter, warm weather may have permitted industrial plants and utilities with fuel switching capabilities and on interruptible gas supply contracts to remain on lower priced natural gas.

By the end of December the number of days of forward supply, based on historical consumption, represented about 66 days, up 3 days from the close of the year before. If the Atlantic region is excluded from the calculation,

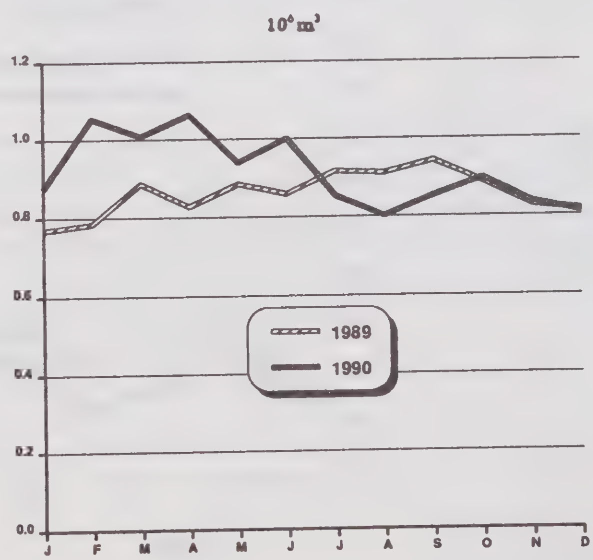
Figure 7.3
Distillate Fuel Oil Stocks



because a large portion of Atlantic supplies are directed to export markets and the region is not 'pipeline-connected' to domestic supplies, the number of days of supply would be reduced to 61.

Stocks referred to in this section do not include estimates of crude oil held in pipeline tankage. If these stocks were included, it is estimated that the number of days of supply would increase to 73 days.

Figure 7.4
Residual Fuel Oil Stocks



8. Crude Oil and Product Prices

- *International and domestic crude oil and petroleum product prices were extremely volatile during the fourth quarter as a result of the Persian Gulf crisis.*

- *Price differentials between Canadian light, sour and heavy crude have increased significantly since January 1990.*

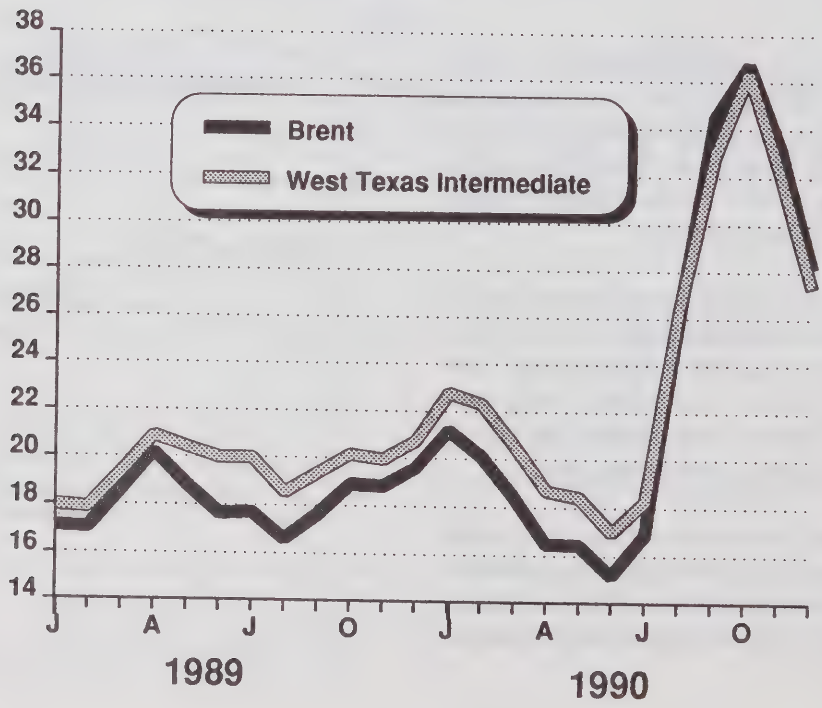
8.1 International Crude Oil Prices

Crude oil prices were extremely volatile over 1990, with significant peaks and troughs recorded throughout the year. While many factors contributed to price volatility, two major influences were OPEC's high level of crude oil production over the first half of 1990 and the conflict in the Persian Gulf in the second half of the year. West Texas Intermediate (WTI) averaged US$24.45/bbl in 1990, up from US$19.60/bbl in 1989.

During the early part of the first quarter of 1990, crude oil prices were relatively firm. Unusually cold weather conditions experienced in northern hemisphere oil markets (in particular, the U.S.) moved prices upwards. As the quarter progressed, however, prices steadily weakened as oil supply and demand fundamentals began to exert more influence on world oil markets. The effects of lower-than-expected oil demand growth, OPEC overproduction, a contraseasonal stock build, and a slowdown in economic activity resulted in weak crude oil prices. Nevertheless WTI averaged US$21.90/bbl over the first quarter, up US$3.55/bbl from year-earlier levels.

World oil prices continued to decline over the second quarter as OPEC failed to achieve an agreement at its May meeting to curb crude oil production. OPEC crude oil output averaged 23.6 MMB/D over the quarter, 1.5 MMB/D above its production ceiling. With world oil demand growth still relatively weak, oil inventories were built at a rate of 2.6 MMB/D, double the stock build recorded over the same quarter in 1989. Consequently, WTI averaged US$18.05/bbl over the quarter, down US$3.85/bbl from the first quarter.

Figure 8.1
International Crude Oil Prices
US$/barrel



At the beginning of the third quarter, soft oil markets resulted in a further decline in prices. However, prices firmed leading up to the July 26 OPEC Ministerial meeting as oil markets anticipated a return to production control. OPEC's meeting ended in an agreement by all members to increase its crude oil production quota by only 400 MB/D, to 22.5 MMB/D. In effect, to meet its new output ceiling, OPEC members' production would be up to 1 MMB/D lower (the volume of overproduction by Kuwait, Saudi Arabia and the UAE). OPEC also raised its crude oil reference price from \$18/bbl to \$21/bbl.

Crude oil prices rose dramatically following the August 2nd invasion of Kuwait, with WTI reaching US\$32/bbl on August 23. Prices also strengthened following the decision by the U.N. Security Council to embargo Iraqi and Kuwaiti oil, removing 4.1 MMB/D from the market. OPEC held an emergency Ministerial meeting in August, where they agreed to temporarily abandon production restraints, thereby allowing members to increase oil output to maximum productive capacity.

Prices remained volatile throughout the third and fourth quarters, averaging US\$25.90/bbl and US\$31.95/bbl, respectively. The loss of Iraqi and Kuwaiti crude oil was entirely offset by higher OPEC crude oil production and through inventory drawdowns. Despite this, crude oil prices continued to be vulnerable to speculation in the oil market, responding to political and military reports emanating from the Gulf, rather than to oil supply/demand fundamentals.

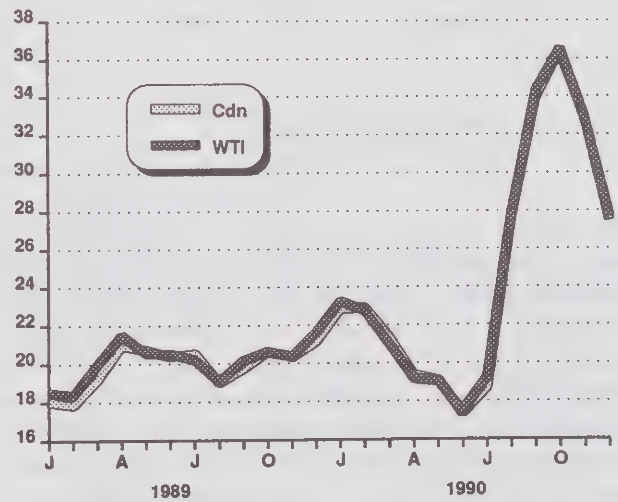
8.2 Domestic Crude Oil Prices

The price of Canadian Par crude oil (the Canadian benchmark crude at 40^{o}API, 0.5% S) averaged \$27.64/bbl in 1990 compared to an average \$22.17/bbl in 1989. The year-over-year increase in the price of Canadian crude followed the trend set in the international market, which primarily reflected the crisis in the Persian Gulf.

In the fourth quarter of 1990, Canadian Par crude averaged \$35.91/bbl, an increase of \$6.69/bbl over the third quarter average. Canadian crude posted an all-time high price in the month of October, averaging \$40.65/bbl. This significant increase in Canadian prices reflected the international market uncertainties and wild gyrations of world crude oil prices during the lead-up to the Persian Gulf war.

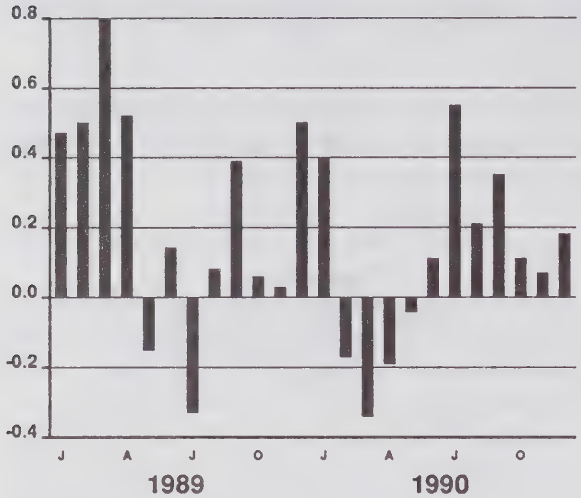
Figure 8.2.1 illustrates the close relationship between the price of Canadian Par crude oil and the U.S. benchmark crude West Texas Intermediate (WTI).

Figure 8.2.1
Canadian Par Crude
vs WTI (NYMEX*) at Chicago
US\$/bbl



The differential between Canadian Par and WTI NYMEX prices, on a calendar basis in Chicago, is illustrated in Figure 8.2.2. The average differential observed in the fourth quarter of 1990 was US\$0.14/bbl in favour of the U.S. crude, compared to an average US\$0.37/bbl in the third quarter.

Figure 8.2.2
Canadian Par vs WTI (NYMEX*)
(Differential at Chicago)
US$/bbl



* New York Mercantile Exchange

Figure 8.2.3
Comparison of Domestic Light and Heavy Crude Oil
(Actual Alberta Purchase Price)
$/bbl

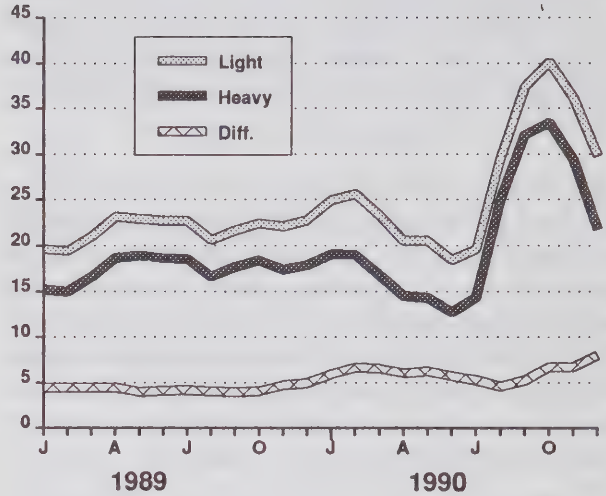


Figure 8.2.3 compares actual prices for Alberta light and heavy crude oil, purchased for use in Canada at main trunk line injection stations. On average, reported light conventional crude oil quality during the fourth quarter was 37.4°API, 0.46% sulphur and blends of heavy crude were 24.1°API, 2.64% sulphur. The differential between Canadian light and heavy crude oil prices during the fourth quarter was $7.12/bbl, $2.08/bbl higher than the third quarter differential. The increase in the differential can be attributed to a glut of heavy crudes on the international market resulting from a disproportionate increase in OPEC production of heavy crude to replace lost production from Kuwait and Iraq. As a result, prices for heavy crude were weak.

8.3 Export Prices

Figures 8.3.1 and 8.3.2 illustrate the relationship between light crude oil export prices and domestic prices.

Prices of light crude oil exported to the United States via the IPL system were netted back to Edmonton and adjusted to 40°API, on a stream by stream basis. These prices were then compared to Canadian Par crude oil prices, also at Edmonton.

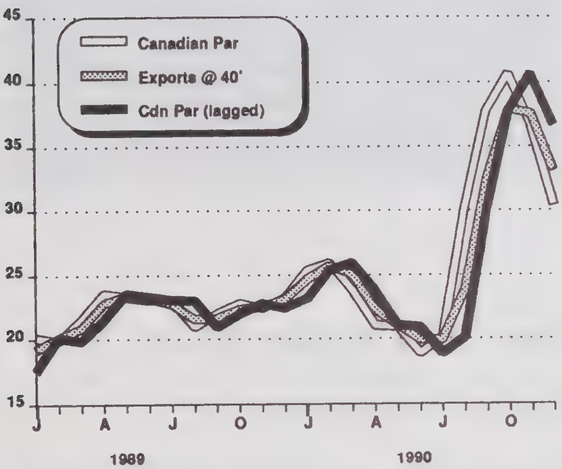
As can be observed in figure 8.3.1, in a period of declining prices, exports would appear to be more

expensive than Par crude for the same month; and, in a period of increasing prices, exports would appear to be cheaper. An evaluation on that basis alone would be misleading. Canadian Par crude prices were therefore "lagged" one month to normalize for differing delivery times of export crude.

Figure 8.3.1

Export vs Canadian Par Crude Prices

$/bbl



For comparison purposes, an average of the current month's Par crude and its lagged price were calculated. Figure 8.3.2 illustrates the differential between this composite average Par crude and the average export price.

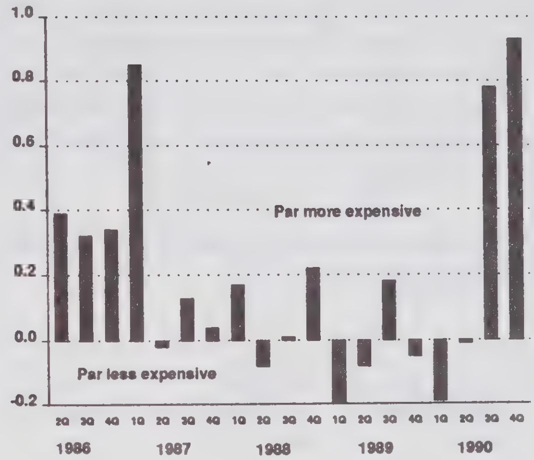
In figure 8.3.2 the apparent discount of export prices in both the third and fourth quarters, relative to domestic prices, resulted from a number of factors. During this period, the threat of war in the Persian Gulf caused crude oil prices to be extremely erratic. Such volatility could introduce some anomalies into this analysis. Higher prices in the second half of 1990, an increase in the availability of light crude for the export market and a generally oversupplied international market combined to force the discount higher.

Figure 8.3.2

Export vs Canadian Par

Price Differential

$/bbl



8.4 Canadian Crude Oil Price Differentials

The relative crude oil price differentials between Canadian light, sour and heavy crude have increased significantly since January 1990.

As with Canadian crude oil prices, price differentials in Canada follow the trends set in international markets. Trends in differentials indicate similar increases in both the domestic and international markets.

The rationale for the increases relates to the fundamental factors of international supply and demand. The large increase in the differentials in the first half of 1990 coincided with overproduction by OPEC, at times by as much as 1.5 million barrels per day above their own production limits. This incremental production came primarily from the Persian Gulf members and took the form of sour and heavy crudes. With more sour and heavy crude on the world market, and with the world already oversupplied, the prices of sour and heavy crude fell relative to light crude.

The invasion of Kuwait by Iraq in August 1990 removed about 4.1 million barrels per day from the world market as a result of international sanctions. Saudi Arabia and Iran and, to a lesser extent the UAE and Venezuela, replaced the shortfall with increased production of heavy and sour crudes. As well, the removal (destruction) of about 750 MB/D of Kuwait's sophisticated refining capacity further exacerbated the situation. The above factors taken together with rapidly fluctuating prices and a glut on the world market, stifled the demand for sour and heavy crude and, to some extent, placed a premium on light sweet crude.

Figure 8.4.1 and 8.4.2 illustrate the increase in Canadian crude oil price differentials.

Figure 8.4.1
Canadian Par vs Bitumen Prices
$/bbl

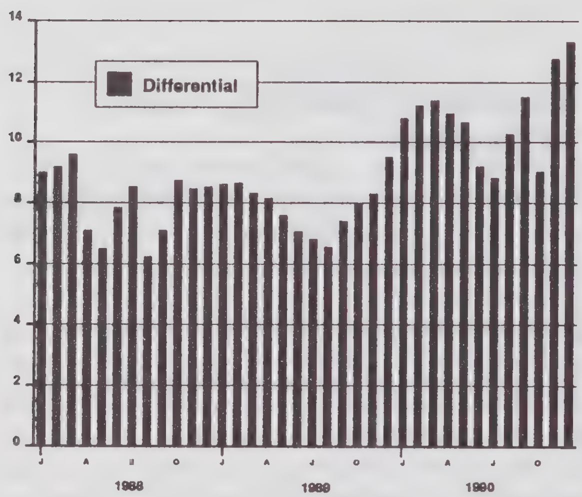
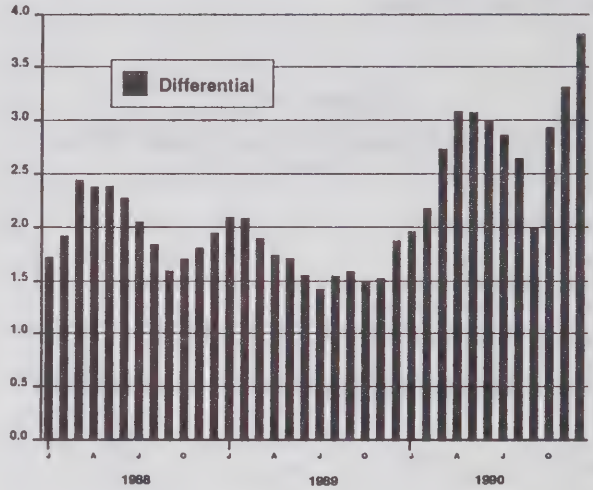


Figure 8.4.2
Canadian Par vs Alberta Light Sour Prices
$/bbl



8.5 Petroleum Product Prices

Price Trends (Gasoline and Diesel)

The average price for regular unleaded gasoline in Canada (self-serve outlets) increased 12.5 cents per litre, or 24% in 1990 (December 25, 1990 vs December 26, 1989). During the year average crude costs increased 11.4 cents per litre; federal taxes, 1.3 cents per litre; and average provincial taxes, 0.8 cents per litre. The combined crude price and tax increases, totalling 13.5 cents per litre, were not fully covered by the average retail price increase.

During 1990, prices increased in all of the 10 cities surveyed. The increases ranged from 10.7 cents per litre

in Vancouver to 18.2 in Halifax. Price wars prevailed in Toronto throughout the year and, although less frequently, in Regina. (See Appendix VIII)

Retail diesel prices increased an average of 11.5 cents per litre during 1990. Increases, which were recorded in each of the 10 cities, ranged from 7.1 cents per litre in Winnipeg to 21.7 cents per litre in Halifax.

During the fourth quarter of 1990, gasoline and diesel prices began to stabilize across Canada.

Throughout the fourth quarter 1990, heating oil prices were up in response to market reaction to the Persian Gulf crisis. At the end of 1990, the average price was 44.5 cents per litre, 14.3 cents per litre higher than in December 1989. During the year, prices increased in all of the 10 centres surveyed. The increases ranged form 10.0 cents per litre in Toronto to 18.3 cents per litre in Montréal.

Figure 8.5.2
Regular Unleaded Gasoline Prices
(10 City Average)

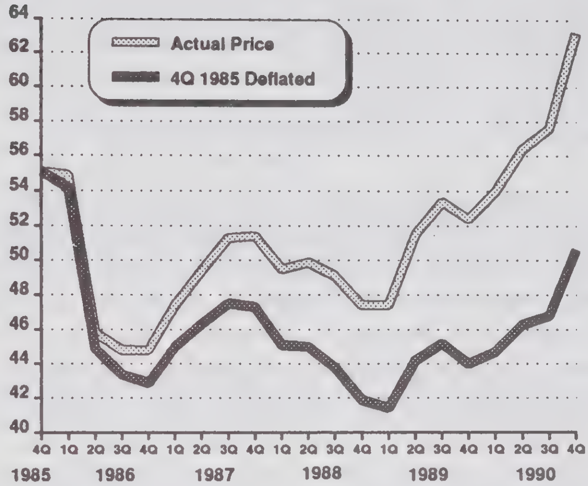
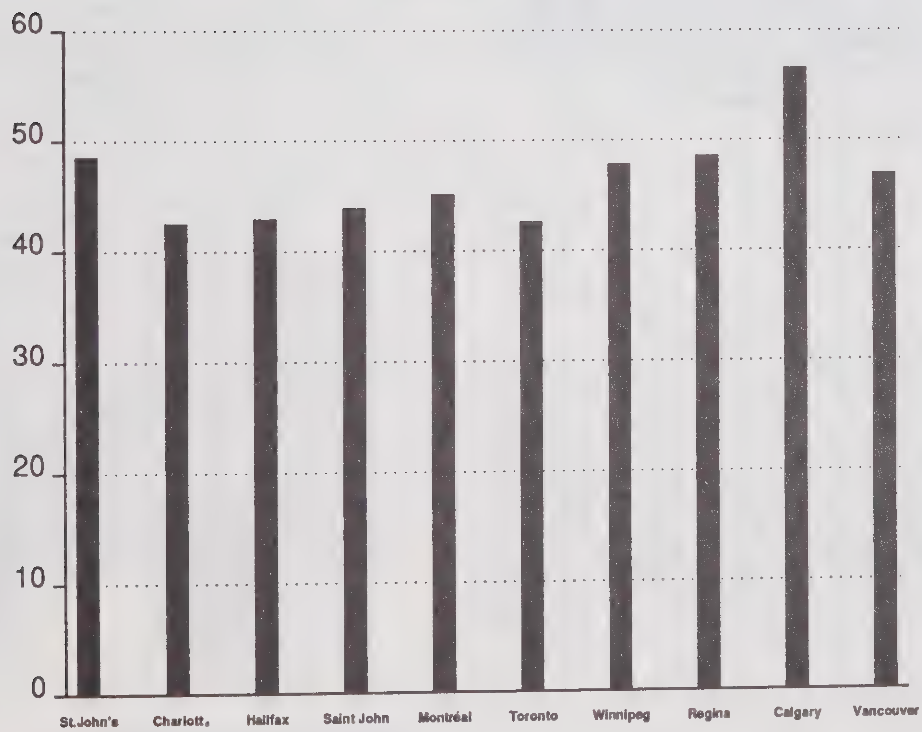


Figure 8.5.1
Average Consumer Furnace Oil Prices
(December 1990)
cents/litre



While Canadian crude costs increased 13.3¢/litre during the fourth quarter (December 25 vs September 25), 5.5 cents of the increase was in October, another 5.3 in November and only 2.5 cents of the increase in December. Yet regular unleaded gasoline prices increased only an average 3.8 cents per litre, or 6.2%, during the fourth quarter.

Consumption Taxes on Petroleum Products

The federal sales tax rate of 13.5% remained constant throughout the year. However, the actual cents per litre derived from this base rate and reviewed quarterly by the Department of Finance, resulted in a 0.36 cent per litre increase in gasoline and a 0.27 cent per litre increase in diesel. The federal excise tax on gasoline and diesel was unchanged at 8.5 and 4.0 cents per litre, respectively. (See Appendix IX)

During 1990 provincial and territorial taxes increased in all provinces except Quebec, Manitoba, Saskatchewan and the Yukon Territories. Prince Edward Island increased its ad valorem rates on gasoline and diesel by 3%. Nova Scotia increased its ad valorem rate by 2.25% on gasoline and 10.5% on diesel. Nova Scotia's increases contribute to their Highway 2000 Fund, which is to improve the 100 series highways by the year 2000. At the time, this resulted in a 4.5 cent per litre increase in the price of diesel. The total increase in Nova Scotia's diesel tax from December 1989 to December 1990 was 7.6 cents per litre or 86%.

The spread between Canadian and American average retail price for all grades of motor gasoline increased slightly from 21.0 cents per litre in December 1989 to 22.4 cents per litre in December 1990. The largest difference was in July, 23.6 cents per litre, and the smallest was in September, 18.2 cents per litre.

In the latter half of 1990 the situation in the Persian Gulf influenced gasoline prices in both Canada and the United States. At first the price increases in the United States occurred faster and were greater than those in Canada. In August, September and October the differential was diminishing but by November it was returning to pre-invasion level.

Higher taxes in Canada accounted for about 62% of the differential in December 1990 down from 68% in December 1989. The balance of the difference is attributable to higher refining and marketing costs and/or profits in Canada.

Figure 8.5.3
Average Retail Price of Motor Gasoline
(Canada vs United States)
cents/litre

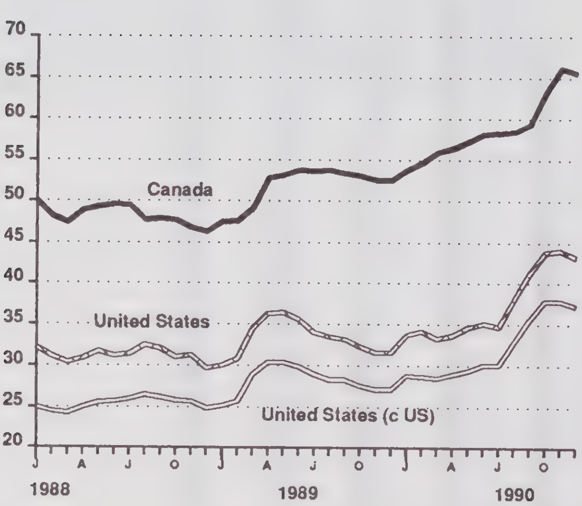
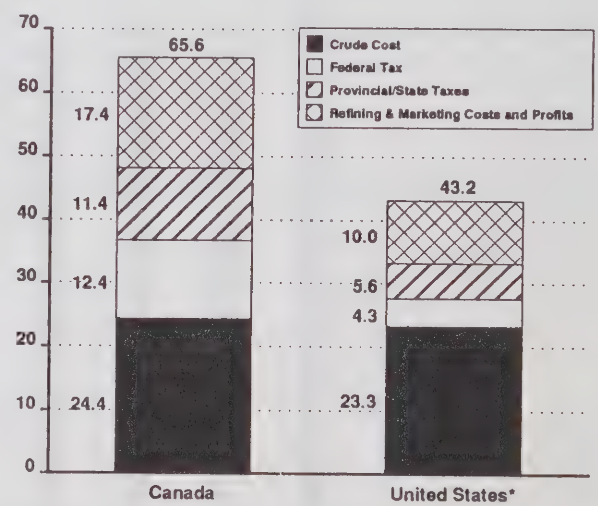


Figure 8.5.4
Breakdown of Average Pump Price
(December 1990)
cents/litre



** Exchange rate = 1.1600*

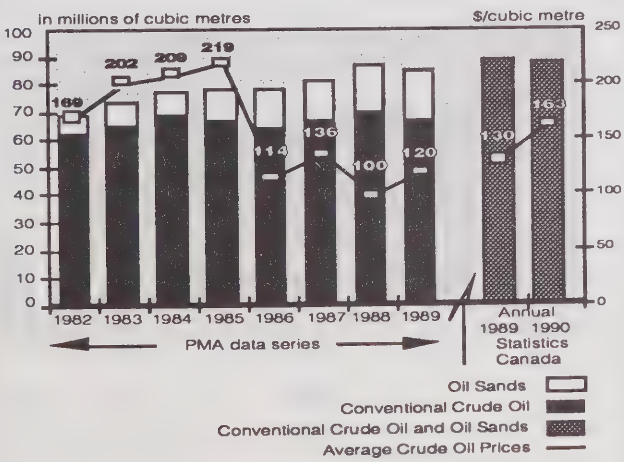
9. Financial Performance of the Canadian Oil and Gas Industry

The following section was prepared by the Petroleum Monitoring Agency (PMA). Further information is available from V. Stanciulescu (613) 995-2100 and F. Laberge 996-8035.

- *Net income after unusual items rose 44% to $2 billion in 1990 above that realized in 1989.*
- *The rate of return on average shareholders' equity for the total Canadian petroleum industry was 5.3% in 1990 against 3.8% in 1989. The return on average capital employed increased to 4.8% from 4.2% in 1989.*
- *Internal cash flow increased 10% to $8.2 billion in 1990 from $7.5 billion in 1989.*
- *Gross capital expenditures increased 4% to $6.8 billion in 1990 but the reinvestment rate declined to 82% from 85% in 1989.*
- *Dividend payments in 1990 rose 14% to $1.5 billion from $1.3 billion in 1989.*
- *Long-term debt as a percent of capital employed was 38% in 1990 down from 39% in 1989 and 43% at its peak in 1986.*

Total sales revenues increased 15% ($6 billion) to $45.8 billion in 1990 from $39.8 billion recorded in 1989. Increased sales revenues resulted from higher prices for crude oil and petroleum products, triggered by the uncertainty caused by events in the Persian Gulf.

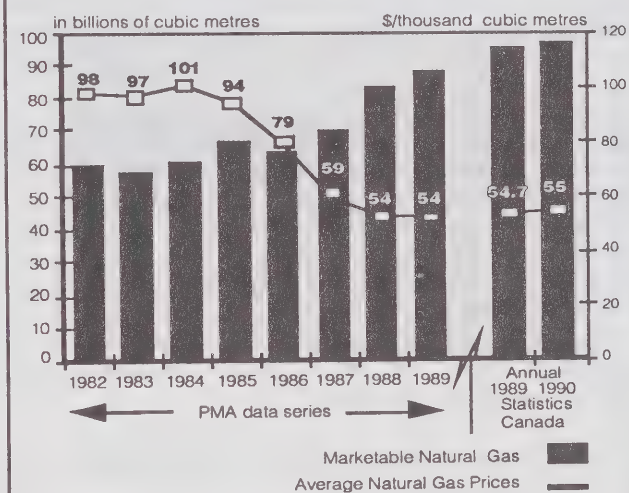
Figure 9.1 Crude Oil Volumes and Average Prices: 1982 - 1990



Average crude oil prices in 1990 were approximately 26% higher than in 1989 and at the highest level since 1985 (Figure 9.1). The rise in crude oil prices resulted in a revenue increase of almost $3 billion, despite a slight drop in production volumes. In addition, prices for gas plant liquids increased significantly, as supply disruptions at extraction plants in the United States increased prices in Canada. However, marketable natural gas production and prices in 1990 rose only marginally.

Higher revenues from refined petroleum products were due to larger sales volumes and the flow through to consumers of increased feedstock costs and higher federal sales and excise taxes.

Figure 9.2 Marketable Natural Gas Volumes and Average Prices: 1982 - 1990



Note: The data for figures 9.1 and 9.2 are taken from the PMA's Monitoring Survey data base except for the two end bars which are derived from Statistics Canada and EMR Oil and Gas Branch. The two data series are **not** entirely comparable since the PMA data shows prices to the producers, while the other data include transportation and gathering costs and are, therefore, higher than PMA numbers. The Monitoring Survey covers approximately 90% of the industry, compared with 100% for the other data series.

Net income from all Canadian operations of the petroleum industry rose 44% ($610 million) to $2 billion in 1990 over 1989. The combined impact of higher sales revenues (up $6 billion), gains on sales of assets (up $545 million), and lower E&D expenses charged to current operations (down $170 million), more than offset increases in depletion, depreciation and amortization charges (up $445 million), and 'other expenses' (up $4.4 billion). The latter category includes operating costs, royalties and feedstock costs, all of which were significantly higher. Increased royalties and feedstock costs were the result of higher crude oil prices.

Increases in unusual write-offs (up $665 million) were reported by a number of companies in the latter part of 1990. Most of these write-offs represent charges to previously capitalized costs because of increased uncertainty about the timing and feasibility of oil production from particular areas, and provisions made for workforce adjustments.

Net income before taxes increased 50% ($1.2 billion), resulting in the provisions for current income taxes rising $865 million to $1.6 billion in 1990. However, deferred income taxes dropped 56% ($225 million) to $180 million in 1990. Apart from increased earnings, higher current taxes in 1990 were due to deferral of tax liability from 1989 to 1990, following a corporate restructuring. This change contributed to the lower level of deferred taxes in 1990, which was also affected by the large write-offs (Table 9.7).

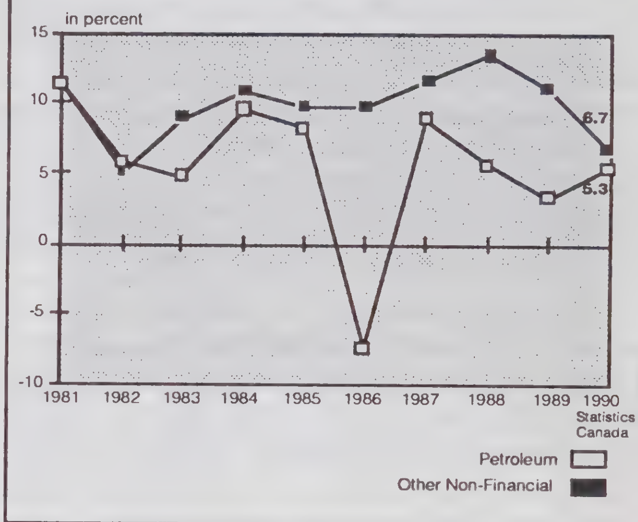
Table 9.1 Overview of Total Industry

Annual

	1989	1990	Change	
	---- $ billions ----			(%)
Total Sales Revenue	39.8	45.8	6.0	15
Other Revenues	0.6	1.0	0.4	67
Total Expenses	37.9	42.6	4.7	12
All Current Taxes	0.7	1.6	0.9	123
Deferred Taxes	0.4	0.2	-0.2	-56
Net Income before Extraordinary Items	**1.3**	**1.8**	**0.5**	**43**
Extraordinary and Other Items	0.1	0.2	0.1	54
Net Income after Extraordinary Items	**1.4**	**2.0**	**0.6**	**44**
Internal Cash Flow	**7.5**	**8.2**	**0.7**	**10**

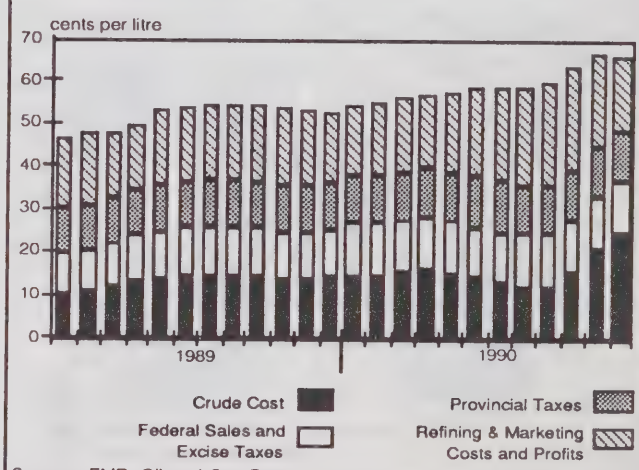
The rate of return on average shareholders' equity for the total Canadian petroleum industry was 5.3% in 1990 against 3.8% in 1989. Since 1982, the rates of return on equity for the petroleum industry have been constantly below those for all other non-financial industries (Chart 3). The petroleum industry's return on average capital employed increased to 4.8% from 4.2% in 1989.

Chart 3. Rates of Return on Shareholders' Equity



Internal cash flow, unaffected by non-cash items, such as gains on sales of assets, write-offs and deferred taxes, increased 10% ($720 million) to $8.2 billion in 1990.

Figure 9.4 Average Retail Price of Motor Gasoline: Monthly, 1989 - 1990



Source: EMR, Oil and Gas Branch

Canadian-controlled companies' net income in 1990 rose 16% ($85 million) to $640 million. Sales revenue increases of $2.6 billion (21%) were partly offset by increases in depletion, depreciation and amortization, and interest charges, up $215 million and $135 million respectively. 'Other expenses', which includes operating and feedstock costs, rose $1.8 billion, or 19%. Earnings prior to income taxes and minority interests rose $345 million (44%) in 1990. However, a $240 million increase in current and deferred income taxes kept the net income rise to 16% ($85 million) in 1990. The income tax increase over 1989 was due to the increase in the pre-tax income. While the statutory rate remained unchanged, the effective rates of tax increased slightly due to the taxation effect of acquisitions of assets, and the application of the Large Corporation Tax to the entire year 1990 vs. only six months in 1989. Internal cash flow rose 19% to $3.1 billion in 1990 from $2.6 billion in 1989.

Foreign-controlled companies' net income rose 63% ($525 million) to $1.4 billion in 1990. Their strong performance was primarily due to higher sales revenue of 13% ($3.4 billion), and gains on sales of assets increased by $505 million in 1990. Also contributing to the increased earnings were reduced E&D charges to current operations (down $165 million) and lower interest expenses (down $150 million). Partly offsetting these positive factors, were higher 'other expenses' of $2.6 billion (which includes operating and feedstock costs) higher depletion, depreciation and amortization charges of $230 million, and large increases in write-off charges which totaled $620 million in 1990. The latter charges represent write-offs of previously capitalized costs to reflect current market conditions, as well as provisions for workforce adjustments.

Income before income taxes and equity earnings rose 54% ($845 million) to $2.4 billion in 1990. However, current income taxes increased $715 million to $1.2 billion in 1990 but deferred taxes decreased from $295 million in 1989 to negative $15 million in 1990. The increase in current taxes was mostly due to higher pre-tax earnings and to deferral of tax liability from 1989 to 1990 following a corporate restructuring. The recapture of deferred taxes was also the result of divestment activities. Internal cash flow, unaffected by non-cash items, rose 5% ($220 million) to $5.1 billion in 1990.

Dividend payments by the petroleum industry increased 14% to $1.5 billion in 1990 from $1.3 billion in 1989. Dividends paid by Canadian-controlled companies increased 20% to $470 million, while dividend payments by foreign-controlled companies rose 12% to $1 billion (Table 9.2).

Table 9.2 Dividend Payments

Annual

	1989	1990	Per Cent of Net Income(a) 1989	1990
	- -$ millions - -		(%)	
Canadian-Controlled	392	470	71	73
Foreign-Controlled	930	1043	112	77
Total Industry	1322	1513	96	76

(a) Percentages are derived by dividing dividend payments by the net income.

Overall gross capital expenditures for the petroleum industry increased 4% ($230 million) to $6.8 billion in 1990 from $6.6 billion in 1989. Capital expenditures, net of grants and incentives, rose 5% as incentives dropped 76% to $40 million from $160 million in 1989 (Table 9.3).

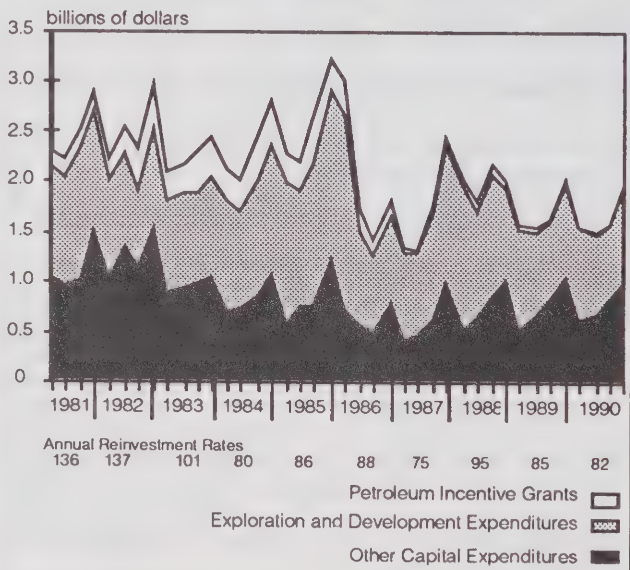
Table 9.3 Capital Expenditures and Reinvestment Rates

Annual

	1989	1990	Change	
	--- $	billions ---		(%)
Gross Capital Expenditures	6.6	6.8	0.2	4
Less: Incentive Grants	0.2	-	-	-76
Net Capital Expenditures	6.4	6.8	0.4	5
Reinvestment Rate: Net Capital Expenditures as a Per Cent of Cash Flow	85%	82%		

Exploration and development outlays, including incentives, increased 2% to $3.6 billion in 1990, whereas other capital expenditures increased 6% to $3.2 billion. Gross capital outlays for Canadian-controlled companies rose 14% to $2.9 billion, while those of foreign-controlled companies declined 3% to $3.9 billion.

Figure 9.5 Capital Expenditures and Reinvestment Rates: 1981-1990



The total reinvestment rate declined to 82% in 1990 from 85% in 1989, due to cash flow increasing at a faster pace than net capital expenditures (Table 9.4). The reinvestment rate for Integrateds and Refiners decreased to 75% from 85%, while that of the Oil and Gas Producers increased to 88% from 86%.

Table 9.4 Total Capital Expenditures (Net Of Incentive Grants) as a Per Cent of Internal Cash Flow

Annual

	1989	1990
	-------(%)	------
Integrateds and Refiners	85	75
Canadian-Controlled	116	106
Foreign-Controlled	78	67
Senior Oil and Gas Producers	72	75
Canadian-Controlled	67	67
Foreign-Controlled	76	81
Junior Oil and Gas Producers	121	117
Canadian-Controlled	117	118
Foreign-Controlled	129	116
Oil and Gas Producers	86	88
Canadian-Controlled	86	86
Foreign-Controlled	85	89
Total Industry	**85**	**82**
Canadian-Controlled	93	91
Foreign-Controlled	81	77

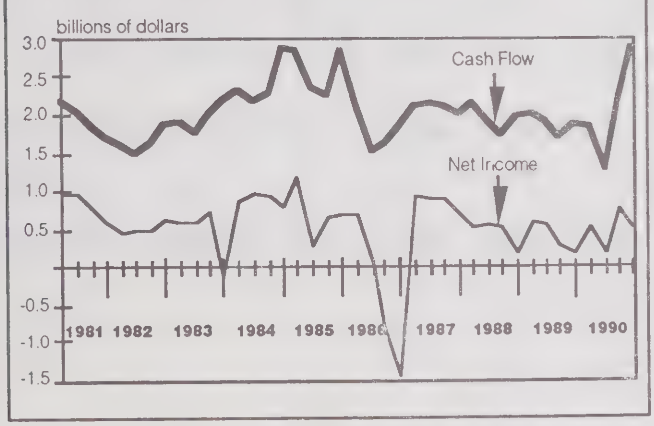
Fourth Quarter 1990:

Net Income rose $490 million to $615 million in the fourth quarter of 1990 from $125 million for the corresponding 1989 period, due mainly to increases in crude oil prices as a result of uncertainty caused by events in the Persian Gulf. While sales revenues rose 29% or $3 billion, the main categories of operating expenses, rose 21%. One factor which partly offset the increase in net income was a large rise of $610 million in write-offs declared during the quarter. Net income before income taxes rose $670 million to $1.1 billion. However, an increase of $410 million in current taxes kept the net income after tax rise to $490 million. Internal cash flow rose 53% to $2.8 billion.

Overall capital expenditures in the fourth quarter of 1990 declined 2% to $1.9 billion. Exploration and development spending decreased slightly to $935 million, while other capital expenditures declined 3% to $995 million.

The reinvestment rate in the fourth quarter of 1990 was 68%, down from 104% for the corresponding 1989 period.

Figure 9.6 Net Income and Cash Flow 1981-1990: Quarterly Data



Note: This report was prepared on the basis of the quarterly data submitted by individual companies to the PMA via Statistics Canada. In contrast to the bi-annual PMA survey presentation, the report covers the combined results of upstream, downstream and other Canadian operations but excludes the results of companies' foreign activities. Nonetheless, the information contained in this analysis gives a reliable overview of the industry's financial performance for the year 1990.

Debt to Equity Analysis:

In 1990 total industry's long-term debt dropped 2% ($490 million) to $24.4 billion from $24.9 billion recorded in 1989 (Table 9.9). Canadian-controlled companies increased their debt by 10% ($895 million), with most of the increase required for the purchase of assets and consolidation of minority interest. The foreign-controlled companies decreased their debt by 9% ($1.4 billion) through the sale of assets.

Total shareholders' equity rose 3% ($1.1 billion) in 1990, with both controlled groups recording the same percentage increase. The change in the equity structure (common shares, retained earnings and contributed surplus) between 1989 and 1990 was due primarily to a company's restructuring. This involved a reduction in share capital and a corresponding increase in contributed surplus, together with a transfer from contributed surplus to retained earnings.

Although the merger and acquisition activity remained strong through 1990, it was accomplished with less reliance on borrowed funds. Other sources of funds were used, such as proceeds from the sale of assets. The ratio of debt to capital employed (defined as total long-term debt plus total equity) declined considerably from its peak in 1986 as petroleum companies limited their reliance on long-term debt and increased their equity position (Figure 9.7). Long-term debt as a percent of capital employed was 38% in 1990 down from 39% in 1989 and 43% at its peak in 1986.

Figure 9.7 Long-Term Debt to Capital Employed

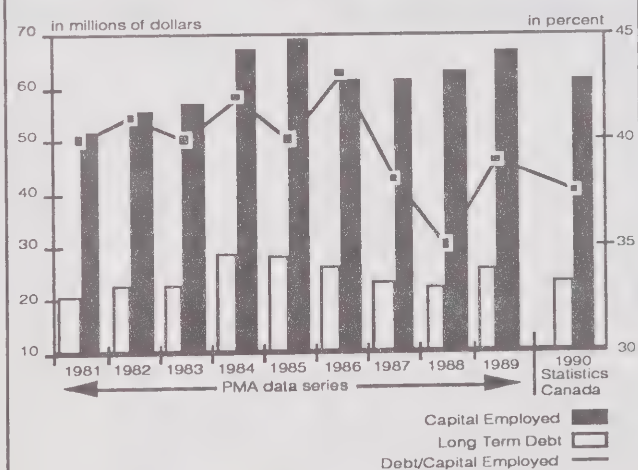


Table 9.5

Capital Expenditures of Petroleum Industry
Annual

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1989	1990	Change %	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions			$ millions		
Exploration and Development									
E&D Expensed									
Land & Lease Acquisition and Retention	70	83	19	9	12	36	61	71	15
Drilling Expenditures	527	409	-22	181	170	-6	347	239	-31
Geological and Geophysical	355	355	-	51	54	6	304	301	-1
Total E&D Expensed	952	847	-11	241	236	-2	712	611	-14
E&D Capitalized									
Land & Lease Acquisition and Retention	526	691	31	203	343	69	323	348	8
Drilling Expenditures	1779	1744	-2	879	1019	16	900	724	-20
Geological and Geophysical	258	294	14	166	196	18	92	99	8
Total E&D Capitalized	2563	2729	6	1248	1558	25	1315	1171	-11
Total Exploration and Development	**3515**	**3576**	**2**	**1489**	**1794**	**20**	**2027**	**1782**	**-12**
Other Capitalized Expenditures									
Mining	103	83	-19	3	24	-	100	59	-41
New Const., Build., Mach., and Equip.	2551	2476	-3	921	965	5	1630	1511	-7
Used Build., Mach., Equip., & Land	192	428	-	65	22	-66	127	406	-
Other Capital Expenditures	193	222	15	60	77	28	133	145	9
Total Other Capital Expenditures	3039	3209	6	1049	1088	4	1990	2121	7
Total Capital Expenditures	**6554**	**6785**	**4**	**2538**	**2882**	**14**	**4017**	**3903**	**-3**
Capital Grants	160	38	-76	78	22	-72	82	16	-80
Net Capital Expenditures	**6394**	**6747**	**6**	**2460**	**2860**	**16**	**3935**	**3887**	**-1**

Table 9.6

Capital Expenditures of Petroleum Industry
Fourth Quarter

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1989	1990	Change %	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions			$ millions		
Exploration and Development									
E&D Expensed									
Land & Lease Acquisition and Retention	19	20	3	2	3	20	17	17	1
Drilling Expenditures	127	138	9	30	34	13	97	104	7
Geological and Geophysical	94	96	2	28	26	-7	66	70	6
Total E&D Expensed	240	254	6	60	63	5	180	191	6
E&D Capitalized									
Land & Lease Acquisition and Retention	123	158	28	44	68	55	78	90	15
Drilling Expenditures	516	437	-15	277	230	-17	239	206	-14
Geological and Geophysical	59	86	46	36	55	53	23	31	35
Total E&D Capitalized	698	681	-2	357	353	-1	340	327	-4
Total Exploration and Development	**938**	**935**	**-**	**417**	**416**	**-**	**520**	**518**	**-**
Other Capitalized Expenditures									
Mining	21	18	-14	1	1	18	20	17	-18
New Const., Build., Mach., and Equip.	912	685	-25	329	278	-16	583	407	-30
Used Build., Mach., Equip., & Land	44	215	-	7	5	-29	37	210	-
Other Capital Expenditures	49	75	53	15	24	60	33	52	58
Total Other Capital Expenditures	1026	993	-3	352	308	-13	673	686	3
Total Capital Expenditures	**1964**	**1928**	**-2**	**769**	**724**	**-6**	**1193**	**1204**	**1**
Capital Grants	31	9	-71	10	9	-6	21	-	-
Net Capital Expenditures	**1933**	**1919**	**-1**	**759**	**715**	**-6**	**1172**	**1204**	**3**

Table 9.7

Income Statement
Annual

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1989	1990	Change %	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions			$ millions		
Sales Revenues	39766	45797	15	12763	15392	21	27003	30405	13
Other Revenues									
Interest from Canadian Sources	505	393	-22	227	168	-26	277	225	-19
Dividends from Canadian Corporations	66	55	-16	38	42	12	28	13	-53
Foreign Dividends and Interest Revenues	28	18	-35	14	-	-97	13	18	33
Gains on Sale of Assets	16	562	-	57	58	2	-41	504	-
Total Revenues	**40380**	**46825**	**16**	**13099**	**15660**	**20**	**27281**	**31165**	**14**
Expenses									
E & D Expensed	1039	870	-16	243	238	-2	796	632	-21
D, D & A Charges	4833	5278	9	1909	2126	11	2924	3152	8
Other Expenses	29794	34165	15	9226	11016	19	20568	23149	13
Interest Expenses	2330	2316	-1	921	1055	15	1410	1261	-11
Total Operating Expenses	**37996**	**42629**	**12**	**12299**	**14434**	**17**	**25697**	**28195**	**10**
Other Transactions									
Gains on Translation of Currency	133	174	31	35	-5	-	98	179	83
Write-offs and Valuation Adjustments	-149	-812	-445	-48	-91	-89	-101	-721	-
Income before Income Taxes	**2369**	**3559**	**50**	**787**	**1130**	**44**	**1582**	**2429**	**54**
Income Taxes									
Current	704	1571	123	228	383	68	476	1189	150
Deferred (tax allocation method)	402	179	-56	108	193	79	295	-14	-
Net Income after Income taxes	1263	1808	43	451	555	23	811	1254	55
Other Income									
Equity Income	192	186	-3	110	86	-22	83	100	7
Extraordinary Items	-71	-	-	-6	-	-	-65	-	-
Net Income after Extraordinary Items	**1384**	**1995**	**44**	**555**	**641**	**16**	**829**	**1354**	**63**
Cash Flow	**7489**	**8211**	**10**	**2647**	**3149**	**19**	**4842**	**5062**	**5**

	Integrateds and Refiners			Oil and Gas Producers		
	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions		
Sales Revenues	26196	29787	14	13570	16010	18
Other Revenues						
Interest from Canadian Sources	217	181	-17	288	212	-26
Dividends from Canadian Corporations	8	9	8	58	47	-19
Foreign Dividends and Interest Revenues	-	1	-	27	17	-37
Gains on Sale of Assets	53	463	-	-37	99	-
Total Revenues	**26474**	**30439**	**15**	**13906**	**16385**	**18**
Expenses						
E & D Expensed	271	252	-7	767	618	-19
D, D & A Charges	1872	2121	13	2961	3157	7
Other Expenses	21601	24359	13	8192	9806	20
Interest Expenses	994	1036	4	1336	1280	-4
Total Operating Expenses	**24739**	**27768**	**12**	**13257**	**14861**	**12**
Other Transactions						
Gains on Translation of Currency	27	58	115	106	117	10
Write-offs and Valuation Adjustments	-43	-625	-	-105	-186	-77
Income before Income Taxes	1719	2104	22	650	1454	124
Income Taxes						
Current	540	1022	89	164	550	235
Deferred (tax allocation method)	157	-144	-	246	323	32
Net Income after Income taxes	**1023**	**1227**	**20**	**240**	**582**	**143**
Other Income						
Equity Income	61	23	-62	132	163	23
Extraordinary Items	-122	-	-	51	-	-
Net Income after Extraordinary Items	**962**	**1250**	**30**	**422**	**745**	**77**
Cash Flow	**3267**	**3560**	**9**	**4222**	**4651**	**10**

Table 9.8

Income Statement
Fourth Quarter

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1989	1990	Change %	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions			$ millions		
Sales Revenues	10441	13485	29	3343	4589	37	7098	8896	25
Other Revenues									
Interest from Canadian Sources	157	98	-38	77	32	-58	81	66	-18
Dividends from Canadian Corporations	21	14	-33	14	11	-18	7	3	-59
Foreign Dividends and Interest Revenues	5	6	6	1	-	-	4	6	27
Gains on Sale of Assets	-40	62	-	40	25	-38	-80	37	-
Total Revenues	**10585**	**13665**	**29**	**3474**	**4657**	**34**	**7111**	**9007**	**27**
Expenses									
E & D Expensed	258	258	-	61	63	3	197	195	-1
D, D & A Charges	1263	1439	14	534	562	5	729	877	20
Other Expenses	7990	9636	21	2403	3134	30	5587	6502	16
Interest Expenses	594	586	-1	244	278	14	350	307	-12
Total Operating Expenses	**10105**	**11919**	**18**	**3243**	**4038**	**25**	**6862**	**7881**	**15**
Other Transactions									
Gains on Translation of Currency	40	52	32	12	-1	-	27	53	94
Write-offs and Valuation Adjustments	-59	-670	-	-21	-	-	-38	-670	-
Income before Income Taxes	461	1128	145	223	619	178	238	509	114
Income Taxes									
Current	129	540	319	62	155	150	68	385	466
Deferred (tax allocation method)	107	-4	-	52	103	97	55	-107	-
Net Income after Income taxes	224	592	164	109	361	231	115	231	101
Other Income									
Equity Income	-7	22	-	-11	11	-	4	10	150
Extraordinary Items	-91	-	-	-23	-	-	-68	-	-
Net Income after Extraordinary Items	**126**	**614**	**387**	**75**	**372**	**396**	**51**	**241**	**373**
Cash Flow	**1863**	**2841**	**53**	**704**	**1065**	**51**	**1160**	**1777**	**53**

	Integrateds and Refiners			Oil and Gas Producers		
	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions		
Sales Revenues	6914	8620	25	3527	4865	38
Other Revenues						
Interest from Canadian Sources	55	45	-17	102	53	-48
Dividends from Canadian Corporations	3	2	-36	18	13	-32
Foreign Dividends and Interest Revenues	-	1	-	5	5	-4
Gains on Sale of Assets	20	31	60	-59	30	-
Total Revenues	**6992**	**8698**	**24**	**3593**	**4966**	**38**
Expenses						
E & D Expensed	35	61	75	223	198	-12
D, D & A Charges	480	541	13	784	898	15
Other Expenses	5850	6782	16	2140	2854	33
Interest Expenses	249	262	5	345	324	-6
Total Operating Expenses	**6613**	**7646**	**16**	**3492**	**4274**	**22**
Other Transactions						
Gains on Translation of Currency	8	14	71	31	38	22
Write-offs and Valuation Adjustments	-19	-591	-	-40	-79	-99
Income before Income Taxes	368	476	30	93	652	-
Income Taxes						
Current	100	404	304	30	136	353
Deferred (tax allocation method)	25	-232	-	83	228	175
Net Income after Income taxes	243	304	25	-19	288	-
Other Income						
Equity Income	3	-5	-	-9	27	-
Extraordinary Items	-124	-	-	32	-	-
Net Income after Extraordinary Items	**122**	**299**	**145**	**4**	**315**	**-**
Cash Flow	**754**	**1219**	**62**	**1109**	**1622**	**46**

Table 9.9

Balance Sheet

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1989	1990	Change %	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions			$ millions		
Cash, Investments and Marketable Securities	889	809	-9	379	331	-13	509	479	-6
Accounts Receivable:									
Affiliates	5354	6540	22	1951	2231	14	3403	4309	27
All Other	724	473	-35	302	314	4	423	159	-62
Total	6078	7014	15	2253	2545	13	3826	4468	17
Inventories	4091	5458	33	1302	1583	22	2790	3875	39
Other Current Assets	976	884	-9	487	370	-24	488	514	5
Total Current Assets	**12034**	**14165**	**18**	**4421**	**4829**	**9**	**7613**	**9336**	**23**
Net Fixed and Depletable Assets	62233	62142	-	24833	25488	3	37401	36653	-2
Other Long-term Assets	7555	8360	11	3678	4497	22	3876	3864	-
Total Assets	**81822**	**84667**	**4**	**32932**	**34814**	**6**	**48890**	**49853**	**2**
Accounts payable:									
Affiliates	4397	5530	26	2006	2346	17	2392	3184	33
All Other	1949	1610	-17	274	307	12	1675	1302	-22
Total	6347	7140	13	2280	2654	16	4067	4486	10
Other Current Liabilities	3016	4403	46	1813	1874	3	1203	2529	-
Total Current Liabilities	9363	11543	23	4093	4528	11	5270	7015	33
Long-term Debt	22274	22115	-1	7751	8806	14	14523	13309	-8
Accumulated Deferred Income Taxes	10859	10950	1	4222	4287	2	6637	6663	-
Other Long-term Liabilities	2580	2248	-13	946	785	-17	1633	1463	-10
Sareholders' Equity									
Common	15202	14044	-8	8680	7386	-15	6522	6658	2
Preferred	4594	3416	-26	3118	2027	-35	1476	1389	-6
Retained earnings	14588	15167	4	3359	3590	7	11230	11577	3
Contributed surplus	2362	5184	119	763	3405	-	1599	1779	11
Total Liabilities, Deferred Taxes and Equity	**81822**	**84667**	**4**	**32932**	**34814**	**6**	**48890**	**49853**	**2**
Working Capital	**2671**	**2622**	**-2**	**328**	**301**	**-8**	**2343**	**2321**	**-1**

	Integrateds and Refiners			Oil and Gas Producers		
	1989	1990	Change %	1989	1990	Change %
	$ millions			$ millions		
Cash, Investments and Marketable Securities	93	149	60	796	660	-17
Accounts Receivable:						
Affiliates	3417	3970	16	1937	2571	33
All Other	342	152	-56	382	322	-16
Total	3759	4122	10	2319	2892	25
Inventories	3512	4821	37	580	637	10
Other Current Assets	252	237	-6	723	646	-11
Total Current Assets	**7616**	**9329**	**23**	**4418**	**4835**	**9**
Net Fixed and Depletable Assets	28199	27817	-1	34035	34325	1
Other Long-term Assets	2395	2472	3	5159	5889	14
Total Assets	**38210**	**39618**	**4**	**43612**	**45049**	**3**
Accounts payable:						
Affiliates	2612	3238	24	1785	2292	28
All Other	1148	1022	-11	801	588	-27
Total	3761	4260	13	2586	2880	11
Other Current Liabilities	1516	2790	84	1501	1612	7
Total Current Liabilities	5277	7050	34	4087	4492	10
Long-term Debt	8976	8454	-6	13298	13661	3
Accumulated Deferred Income Taxes	5677	5514	-3	5182	5436	5
Other Long-term Liabilities	951	730	-23	1628	1519	-7
Sareholders' Equity						
Common	6693	5066	-24	8508	8978	6
Preferred	1129	15	-99	3466	3401	-2
Retained earnings	9091	9734	7	5497	5433	-1
Contributed surplus	416	3055	-	1946	2129	9
Total Liabilities, Deferred Taxes and Equity	**38210**	**39618**	**4**	**43612**	**45049**	**3**
Working Capital	**2339**	**2279**	**-3**	**331**	**343**	**4**

Appendix I
Production of Canadian Crude Oil and Equivalent

		1989				1990		
		4Q	Year	1Q	2Q	3Q	4Q	Year
		(000m^3/d)						
A.	**Light and Equivalent**							
	Alberta	121.9	124.3	121.5	113.8	117.3	116.4	117.3
	B.C.	6.0	5.2	5.6	5.0	5.1	5.0	5.2
	Saskatchewan	10.5	10.6	11.2	11.6	12.4	12.4	11.9
	Manitoba	2.0	1.9	2.0	2.0	2.0	2.0	2.0
	Ontario	0.7	0.7	0.7	0.7	0.6	0.6	0.6
	Other	5.1	4.9	5.1	5.0	4.9	5.2	5.0
	Total	**146.2**	**147.6**	**146.1**	**138.1**	**142.3**	**141.6**	**142.0**
	Synthetic							
	Suncor	8.5	9.1	9.2	5.0	8.3	10.1	8.1
	Syncrude	24.4	23.6	15.9	28.9	26.7	27.3	24.7
	Total	**32.9**	**32.7**	**25.1**	**33.9**	**34.9**	**37.4**	**32.8**
	Pentanes Plus*	**9.0**	**7.8**	**6.0**	**7.1**	**6.6**	**6.6**	**6.5**
	Total Light	**188.1**	**188.1**	**177.2**	**179.1**	**183.8**	**185.6**	**181.3**
B.	**Heavy Crude Alberta**							
	Conventional	27.2	25.2	27.4	26.8	27.6	28.7	27.6
	Bitumen	18.9	20.5	21.4	19.4	22.3	23.3	21.6
	Diluent	8.0	8.2	9.9	7.6	8.6	10.0	9.1
	Total	**54.1**	**53.9**	**58.7**	**53.8**	**58.5**	**62.0**	**58.3**
	Saskatchewan							
	Conventional	21.7	21.1	21.0	21.3	21.1	21.5	21.2
	Diluent	2.7	2.6	3.0	2.7	2.5	2.8	2.8
	Total	**24.4**	**23.7**	**24.0**	**24.0**	**23.6**	**24.3**	**24.0**
	Total Heavy	**78.5**	**77.6**	**82.7**	**77.8**	**82.1**	**86.3**	**82.3**
C.	**Production**	**266.6**	**265.6**	**259.9**	**256.9**	**265.9**	**271.9**	**263.6**
D.	**Shut-In**							
	Light	3.1	5.3	3.8	7.7	4.3	3.9	4.2
	Heavy	1.4	2.9	1.6	1.3	0.3	-3.9	-0.2
	Total	**4.5**	**8.2**	**5.4**	**9.0**	**4.6**	**0**	**4.7**
E.	**Total Capacity**	**271.1**	**273.9**	**265.3**	**265.9**	**270.5**	**271.9**	**268.3**

*excludes dilent

Appendix II
Supply and Disposition of Canadian Crude Oil and Equivalent

		1989				1990		
		4Q	Year	1Q	2Q	3Q	4Q	Year
		(000m^3/d)						
A.	**Light and Equivalent**							
	Supply							
	Production	188.0	188.1	177.2	179.1	183.9	185.7	181.4
	Newgrade	0.0	0.1	0.5	1.1	1.4	2.4	1.4
	Draw/(Build)	1.4	2.8	3.9	-2.1	5.8	4.2	3.0
	Net Supply	189.4	191.0	181.6	178.1	191.1	192.3	185.8
	Domestic Demand							
	Atlantic	0	0	0	0	0	0	0
	Quebec	10.4	9.3	7.1	11.4	9.7	4.1	8.1
	Ontario	67.3	64.6	67.6	55.4	65.8	70.0	64.7
	Prairies	51.9	52.7	53.7	46.0	49.4	51.6	50.2
	B.C.	16.3	17.3	17.7	17.4	18.8	18.5	18.1
	Total	**145.9**	**143.9**	**146.0**	**130.2**	**143.7**	**144.3**	**141.1**
	Exports	**43.5**	**47.2**	**35.6**	**48.0**	**47.4**	**48.0**	**44.8**
	Total Demand	**189.4**	**191.1**	**181.6**	**178.2**	**191.1**	**192.3**	**185.9**
B.	**Heavy Crude (Blended)**							
	Supply							
	Production	78.6	77.7	82.7	77.9	82.0	86.3	82.3
	Recycled Diluent	1.1	1.2	0.5	1.3	1.5	0.8	1.0
	Draw/(Build)	-3.9	-1.1	-0.5	1.8	2.7	-2.9	0.3
	Net Supply	75.8	77.8	82.7	81.9	86.2	84.2	83.6
	Domestic Demand							
	Atlantic	0.1	0.1	0	0.4	0.9	0.2	0.4
	Quebec	3.7	4.3	5.1	4.9	4.1	1.2	3.8
	Ontario	9.4	9.7	8.9	7.0	8.4	10.2	8.7
	Prairies	4.8	7.3	7.3	11.1	14.6	10.4	10.8
	B.C.	0.8	0.6	0.2	0.3	0.4	0.8	0.4
	Total	**18.9**	**21.9**	**21.6**	**23.6**	**28.4**	**22.8**	**24.1**
	Exports	**56.8**	**55.7**	**61.1**	**57.3**	**57.8**	**61.4**	**59.4**
	Total Demand	**75.7**	**77.6**	**82.7**	**80.9**	**86.2**	**84.2**	**83.5**

Appendix III
Crude Oil Exports by Destination

U.S. PAD* Districts		1989 4Q	1989 Year	1990 1Q	1990 2Q	1990 3Q	1990 4Q	1990 Year
		($000m^3/d$)						
PADD I	Light	7.5	7.4	6.3	7.8	7.8	7.0	7.3
	Heavy	1.2	1.3	1.8	1.1	1.2	1.2	1.3
	Total	**8.7**	**8.7**	**8.1**	**8.9**	**9.0**	**8.2**	**8.6**
PADD II	Light	24.5	27.3	19.0	29.2	28.4	31.2	27.0
	Heavy	50.0	48.3	50.5	50.3	52.5	54.2	51.9
	Total	**74.5**	**75.6**	**69.5**	**79.5**	**80.9**	**85.4**	**78.9**
PADD III	Light	0	0	0	0	0	0	0
	Heavy	1.2	1.5	3.3	1.4	0	0.6	1.3
	Total	**1.2**	**1.5**	**3.3**	**1.4**	**0**	**0.6**	**1.3**
PADD IV	Light	8.9	9.1	9.0	9.5	10.5	8.8	9.4
	Heavy	1.5	2.7	2.3	2.9	3.4	3.4	3.0
	Total	**10.4**	**11.8**	**11.3**	**12.4**	**13.9**	**12.2**	**12.4**
PADD V	Light	2.5	2.8	0.7	1.3	0.8	0.4	0.7
	Heavy	0.4	0.6	0.8	0.8	0.8	1.1	0.9
	Total	**2.9**	**3.4**	**1.5**	**2.1**	**1.6**	**1.5**	**1.6**
U.S.	Light	43.4	46.6	35.0	47.8	47.5	47.4	44.4
	Heavy	54.3	54.4	58.7	56.5	57.9	60.5	58.4
	Total	97.7	101.0	93.7	104.3	105.4	107.9	102.8
Offshore	Light	0	0.4	0.4	0	0	0	0.1
	Heavy	2.5	1.4	2.5	0.8	0	1.6	1.2
	Total	2.5	1.8	2.9	0.8	0.0	1.6	1.3
Total	Light	43.4	47.0	35.4	47.8	47.5	47.4	44.5
	Heavy	56.8	55.8	61.2	57.3	57.9	62.1	59.6
	Total	100.2	102.8	96.6	105.1	105.4	109.5	104.1

** U.S. Petroleum Administation for Defense (PAD) Districts*

Appendix IV
Pipeline Deliveries

		1989			1990		
		4Q	Year	1Q	2Q	3Q	4Q	Year

		1989 4Q	1989 Year	1990 1Q	1990 2Q	1990 3Q	1990 4Q	1990 Year
		(000m³/d)						
A.	**Trans Mountain Pipe Line (TMPL)**							
	Domestic Deliveries							
	Light Crude Oil	12.9	13.9	13.5	14.4	15.4	15.6	14.7
	Heavy Crude Oil	0.5	0.6	0.2	0.3	0.3	0.3	0.3
	Semi Refined Products	6.2	5.4	5.1	5.0	5.6	5.1	5.2
	Refined Products	3.0	2.7	2.7	2.7	2.6	2.6	2.7
	Total	**22.6**	**22.7**	**21.5**	**22.4**	**23.9**	**23.6**	**22.9**
	Foreign Deliveries							
	Tankers	3.8	2.7	4.4	1.6	0.7	4.3	2.7
	Puget Sound Area	2.4	2.7	0.7	1.3	0.9	0.9	1.0
	Total	**6.2**	**5.4**	**5.1**	**2.9**	**1.6**	**5.2**	**3.7**
	Total TMPL	**28.8**	**28.1**	**26.6**	**25.3**	**25.5**	**28.8**	**26.6**
B.	**Interprovincial Pipe Line (IPL)**							
	Domestic Deliveries							
	Light Crude Oil	94.9	93.9	93.3	78.7	88.6	86.8	86.9
	Heavy Crude Oil	16.1	17.9	19.7	17.5	17.9	14.4	17.4
	Other (1)	27.6	26.4	27.6	28.0	23.1	28.3	26.7
	Total	**138.6**	**139.9**	**140.6**	**124.2**	**129.6**	**129.5**	**131.0**
	Foreign Deliveries (2)							
	Light Crude Oil	38.9	42.0	33.4	46.3	42.3	44.3	41.5
	Heavy Crude Oil	51.4	49.6	52.3	51.4	53.9	55.1	53.2
	Total	**90.3**	**91.6**	**85.7**	**97.7**	**96.2**	**99.4**	**94.7**
	Total IPL	**228.9**	**231.5**	**226.3**	**221.9**	**225.8**	**228.9**	**225.7**
C.	**Pipeline to Montreal**							
	IPL Deliveries							
	To Montreal Refineries	15.1	14.5	12.5	16.3	14.3	5.1	12.0
	For Export/Transfer	2.5	2.0	4.5	0.4	0.6	0	1.4
	Total IPL	**17.6**	**16.4**	**17.0**	**16.7**	**14.9**	**5.1**	**13.4**
	Portland-Montreal							
	Montreal Imports (3)	12.5	13.2	16.8	9.2	17.9	24.2	17.0
	Total Mtl Receipts	**27.6**	**27.6**	**29.3**	**25.5**	**32.2**	**29.3**	**29.0**

Note (1): includes petroleum products and NGL's.
(2): includes US domestic curdes delivered to the US.
(3): includes cargoes imported directly into Montreal

Appendix V
Refinery Receipts

	1989 4Q	1989 Year	1990 1Q	1990 2Q	1990 3Q	1990 4Q	1990 Year
	(000m^3/d)						
A. Domestic Receipts							
Light & Equivalent							
Atlantic	0	0	0	0	0	0	0
Quebec	10.4	9.3	7.1	11.4	9.7	4.1	8.1
Ontario	67.3	64.6	67.5	55.3	65.8	70.0	64.7
Prairies	51.8	52.7	53.7	46.0	49.5	51.6	50.2
B.C.	16.3	17.3	17.6	17.4	18.9	18.5	18.1
Total	**145.8**	**143.8**	**145.9**	**130.1**	**143.9**	**144.2**	**141.1**
Heavy							
Atlantic	0.1	0	0	0.4	0.9	0.2	0.4
Quebec	3.7	4.3	5.2	4.9	4.2	1.2	3.9
Ontario	9.4	9.7	8.8	7.0	8.4	10.2	8.6
Prairies	4.9	7.3	7.4	11.1	14.5	10.4	10.9
B.C.	0.8	0.6	0.2	0.3	0.4	0.8	0.4
Total	**18.9**	**21.9**	**21.6**	**23.7**	**28.4**	**22.8**	**24.2**
Other Receipts *							
Atlantic	0.5	0.8	0.8	0.5	0.1	0	0.3
Quebec	1.1	1.2	1.4	1.1	0.4	0.5	0.9
Ontario	4.8	4.3	3.3	3.9	2.9	3.7	3.4
Prairies	4.0	3.4	3.4	2.6	2.9	3.7	3.2
B.C.	5.9	5.8	5.3	5.0	5.9	5.4	5.4
Total	**16.3**	**15.5**	**14.2**	**13.1**	**12.2**	**13.3**	**13.2**
Total Domestic Receipts							
Atlantic	0.6	0.8	0.8	0.9	1.0	0.2	0.7
Quebec	15.2	14.8	13.7	17.4	14.3	5.8	12.9
Ontario	81.5	78.6	79.6	66.2	77.1	83.9	76.7
Prairies	60.7	63.4	64.5	59.7	66.9	65.7	64.3
B.C.	23.0	23.7	23.1	22.7	25.2	24.7	23.9
Total	**181.0**	**181.1**	**181.7**	**166.9**	**184.5**	**180.3**	**178.5**
B. Crude Oil Imports							
Atlantic	47.6	46.3	50.7	47.3	48.3	47.7	48.4
Quebec	25.5	26.5	35.2	25.0	36.9	43.1	35.1
Ontario	2.9	4.3	5.1	2.6	2.1	1.5	2.8
Prairies	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	0	0
Total	**76.0**	**77.0**	**91.0**	**74.9**	**87.3**	**92.3**	**86.3**
C. Total Receipts							
Atlantic	48.2	47.1	51.5	48.2	49.4	47.9	49.1
Quebec	40.7	41.3	48.9	42.4	51.2	48.9	48.0
Ontario	84.4	82.9	84.7	68.8	79.2	85.4	79.5
Prairies	60.7	63.4	64.5	59.7	66.9	65.7	64.3
B.C.	23.0	23.7	23.1	22.7	25.2	24.7	23.9
Total	**257.0**	**258.4**	**272.7**	**241.8**	**271.8**	**272.6**	**264.8**

* *Partially processed oil, gas plant butanes etc.*

AppendixVI
International and Domestic Crude Oil Prices
(US$/bbl)

A. At Source

		Canadian Par	WTI NYMEX	Brent
1990	Jan.	21.66	22.64	21.10
	Feb.	21.72	22.12	19.90
	Mar.	20.18	20.41	18.44
	Apr.	18.09	18.58	16.61
	May	17.81	18.46	16.65
	Jun.	16.07	16.86	15.56
	Jul.	17.39	18.64	17.48
	Aug.	26.25	27.18	27.40
	Sep.	32.63	33.69	35.17
	Oct.	35.09	35.92	36.32
	Nov.	31.53	32.31	33.01
	Dec.	26.22	27.10	28.07

B. At Chicago

		Canadian Par	WTI NYMEX	Brent
1990	Jan.	22.84	23.24	22.89
	Feb.	22.88	22.72	21.64
	Mar.	21.35	21.01	20.36
	Apr.	19.37	19.18	18.43
	May	19.09	19.06	18.43
	Jun.	17.35	17.46	17.35
	Jul.	18.69	19.24	19.27
	Aug.	27.57	27.78	29.21
	Sep.	33.94	34.29	37.08
	Oct.	36.41	36.52	38.12
	Nov.	32.84	32.91	34.84
	Dec.	27.52	27.70	30.08

C. At Montreal

		Canadian Par	Brent
1990	Jan.	23.00	23.42
	Feb.	23.04	22.05
	Mar.	21.51	20.52
	Apr.	19.59	18.63
	May	19.31	18.07
	Jun.	17.57	16.91
	Jul.	18.91	18.86
	Aug.	27.79	28.65
	Sep.	34.15	36.68
	Oct.	36.61	37.86
	Nov.	33.04	34.55
	Dec.	27.73	30.29

Appendix VII
Average Regular Unleaded Gasoline Prices
(Self-Serve)
1989-1990

	1989	---------- 1990 ----------			
	Dec. 26	**March 27**	**June 26**	**Sept. 25**	**Dec. 25**
	----------cents per litre----------				
St. John's (NFLD)	56.8	58.3	59.6	64.4	72.6
Charlottetown	53.8	56.2	57.7	58.5	68.4
Halifax*	52.4	53.8	57.5	56.3	70.6
Saint John (N.B.)	51.9	55.2	55.9	60.1	67.3
Montreal	58.1	60.8	61.9	64.0	71.0
Toronto	47.2	48.5	53.9	59.3	58.8
Winnipeg	50.7	53.9	49.9	56.9	64.9
Regina	45.8	54.9	54.9	58.9	62.9
Calgary	48.1	51.9	53.3	55.7	60.0
Vancouver	54.9	59.9	59.9	64.9	65.6
Average	**52.1**	**54.8**	**56.8**	**60.8**	**64.6**
Consumtion taxes include:					
Federal	11.0	12.1	12.1	12.2	12.3
Provincial	10.6	11.3	11.4	11.3	11.4

**Full-Serve*

Appendix IX
Consumption Taxes on Petroleum Products
(December 1990)

	Ad valorem Mogas	Ad valorem Diesel	Gasoline Reg L	Gasoline Mid UL	Gasoline Prem UL	Diesel
	------------%-----------		-------------------(cents per litre)----------------------			
FEDERAL TAXES						
Sales			3.83*	3.89*	3.94*	2.96*
Excise			8.50	8.5	8.5	4.0
PROVINCIAL TAXES						
Newfooundland[(a)]	23	27	12.4*	12.4*	12.4*	13.5*
Prince Edward Island	23	26	11.3	11.3	11.3	11.1
Nova Scotia	22.25	31.5	12.5*	12.5*	12.5*	16.4*
New Brunswick	24.5	31.5	11.2	11.8	11.8	11.6
Quebec[(b)]			14.4	14.4	14.4	12.45
Ontario			11. 3	11.3	11.3	10.9
Manitoba			9.0	9.0	9.0	9.9
Saskatchewan			10.0	10.0	10.0	10.0
Alberta			7.0	7.0	7.0	7.0
British Columbia[(c)]	22.5	(d)	9.93*	9.93*	9.93*	10.37*
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	(e)	9.0	9.0	9.0	7.7

(a) The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay in Labrador.

(b) Reduced by varying amounts in certain remote areas and within 20 Kilometres of the provincial and borders.

(c) Additional transit tax of 3.0 cents per litre in Vancouver.

(d) The tax on diesel 0.44 cents per litre higher than the unleaded tax.

(e) 85% of gasoline tax.

** Changed since last quarter.*

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional area	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Shut-in capacity	The unused production capability of currently producing oil and gas wells plus the total production capability of all shut-in oil and gas wells, regardless of whether or not they are connected to surface gathering and production facilities.
Synthetic crude oil	Crude oil produced treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

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THE CANADIAN OIL MARKET

Vol. VII, No. 1, Spring 1991

Canadian Oil Markets and Emergency Planning Division
Energy Sector
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The Canadian Oil Market

1 Refined Petroleum Product Demand

- *Sales of refined petroleum products during the first quarter, 1991 continued to fall primarily as a result of the current economic recession.*
- *The current drop in product sales has for the most part been led by a decline in heavy fuel oil and transportation fuels demand.*
- *Oil consumption during the latter half of the decade has failed to fully recover despite lower oil prices and growth in the Canadian economy.*

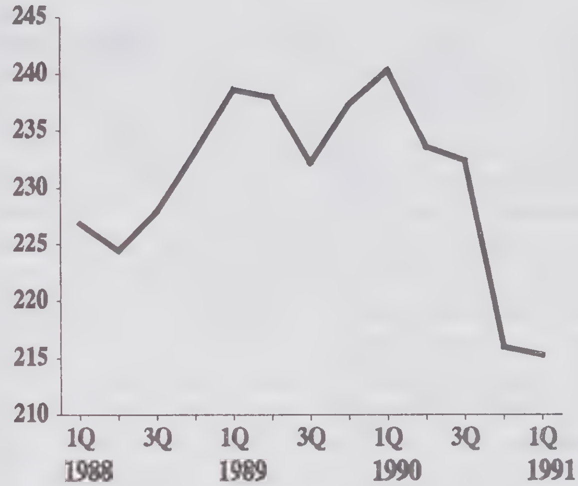
1.1 Seasonally Adjusted Demand

Total sales of refined petroleum products averaged 215 000 m^3/d during the first quarter of 1991, according to data collected and seasonally adjusted by Statistics Canada. This represented a 4% decrease in sales from the previous quarter and a 10% drop from a year earlier.

As illustrated in figure 1.1, the decline in domestic sales of refined products during the first quarter continued a downward trend that emerged early in 1989 following several years of steady growth. This decline was temporarily interrupted during the fourth quarter of 1989 when unseasonably cold weather in eastern Canada resulted in a surge in demand for fuel oils.

The weakness of refined product sales largely reflects the impact of the economic recession and, to a lesser extent, a relatively mild 1990/1991 winter and higher petroleum product prices ensuing from the Persian Gulf crisis.

Figure 1.1
Total Refined Petroleum Product Sales
(Seasonally adjusted)
000 m3/d



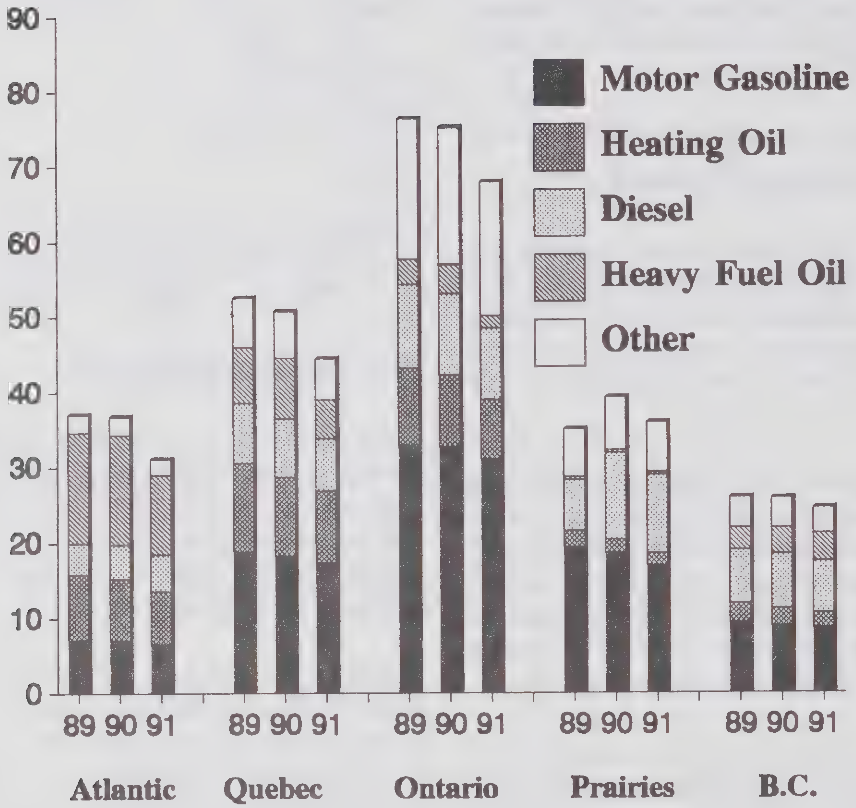
1.2 Unadjusted Demand

Actual domestic sales (before seasonal adjustment) averaged 204 000 m^3/d during the first quarter of 1991. Total sales were 10% below the previous quarter and 11% below the corresponding quarter last year. All regions recorded declines in sales as did all refined petroleum product categories.

A steep drop in heavy fuel oil sales accounted for almost 40% of the total decline in product sales. Sales of heavy fuel oil fell by a third to 21 000 m^3/d reflecting reduced demand in the electric power sector and industrial sectors of eastern Canada. The latter was particularily hard hit by the economic recession.

Motor gasoline sales decreased 5% to 81 000 m^3/d and diesel fuel fell 7% to 39 000 m^3/d. The 'other' refined products category which includes such products as petrochemical feedstocks, liquified gases, jet fuels, asphalts and lubes fell 8% to 35 000 m^3/d. Most of this drop was the result of lower jet fuel and petroleum coke sales.

Figure 1.2.1
Refined Petroleum Product Sales
(First Quarter)
000 m/d



1.3 Refined Petroleum Product Sales - A 10 Year Review

The set of figures on the next page focuses on the volumetric changes that have occurred in product sales over the past decade. Also included for reference is a graph showing the course of real GDP and nominal oil prices in Canada over the same period. Those figures relating to product sales have been derived using year-over-year rolling averages, and are therefore more illustrative of trends than of actual changes in consumption. The first figure is simply a composite of the four figures below it which show the changes in demand in each product category.

The steep decline in consumption during the 1981-82 period was brought about by the combined effects of a downturn in the economy, public and private sector initiatives at oil conservation, and rising oil prices. The decline was pervasive, affecting all product categories, but was particularly pronounced in the transportation and heavy fuel oil (HFO) markets. Demand for the transportation fuels fell by 18 000 m^3/d over the two years, and in fact trended down at a rate of almost 1 000 m^3/d per month in 1982. HFO demand dropped by over 13 000 m^3/d during the same two-year period.

While sales of transportation fuels and 'other' products soon started to recover, in tandem with the upturn in the economy that began in 1983, rising oil prices continued to depress HFO demand for more than another two years. As for heating oil, sales declined throughout the decade, albeit at a diminishing rate. This generally reflected the pace of conversion in the space heating market from oil to natural gas in Ontario and western Canada, and to electricity in Quebec and the Atlantic. Government programs that encouraged retrofitting of insulation in older dwellings was another factor, particularly in the earlier years.

The collapse in oil prices in 1986 abruptly reversed the rising relative price advantage that natural gas and electricity had enjoyed over oil in the preceding 5 years. Aside from providing an added boost to transportation fuel demand, the lower oil prices that ensued in the latter half of the decade mitigated, if not reversed, the deterioration in oil's share in some energy markets. Trends in heating oil and HFO demand in the aftermath of the price collapse serve as cases in point. Nevertheless, with regard to HFO, over half of the incremental demand came from the electric power utilities of eastern Canada which were stepping up their use of HFO to produce electricity not so much because of favourable HFO prices but in order to compensate for a drought-induced shortfall in hydro generation.

The decline in oil product demand that has accompanied the current economic recession has so far not been as severe as the one associated with the previous downturn. Nevertheless, there are certain similarities, chief amongst which is the fact that the transportation fuels and HFO have largely dominated both declines. It is also interesting to note that the correlation between economic growth and oil consumption over the decade has been relatively weak, in contrast to the strong correlations found when real GDP is set against electricity or natural gas demand. One factor has been the relative instability of oil prices vis-a-vis those of the other two energy commodities. Had oil prices been steadier (regardless of their level), oil demand would have more closely tracked GDP over the period. This follows because a steady oil price would tend to influence the level of consumption but not its rate of change. The latter would be left to changes that occurred in real GDP (and/or in some other exogenous variables). This being the case, it would appear that the high and rising oil price level observed prior to 1986, and the impetus it gave to fuel efficiency improvements and 'off oil' substitution, has resulted in a long-term downward shift in oil demand. This conclusion is suggested by the fact that oil consumption in the latter half of the decade failed to fully recover despite lower oil prices and substantial growth in the Canadian economy.

Figure 1.3.1
Changes in Oil Product Demand
000 m3/d

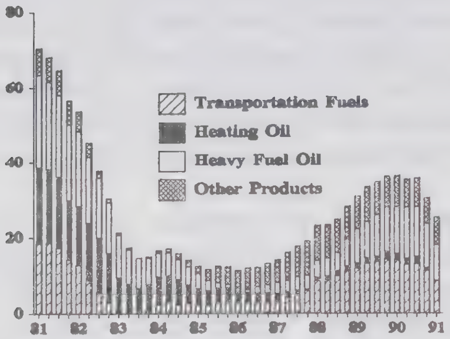


Figure 1.3.2
Real GNP and Oil Prices
Billions of $1986 and CDN $/bbl

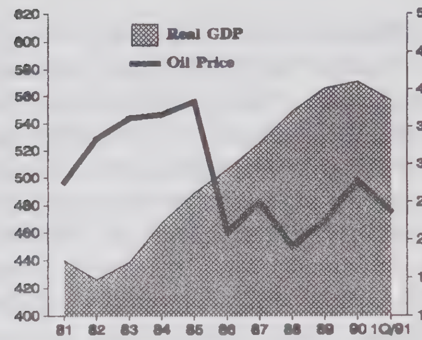


Figure 1.3.3
Changes in Transportation Fuel Demand
000 m3/d

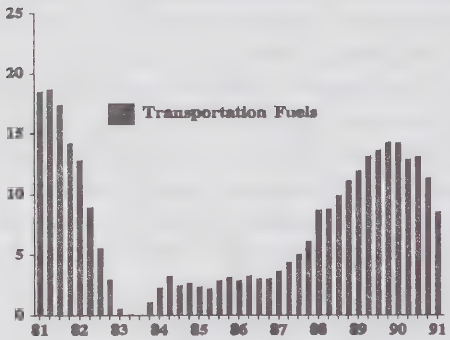


Figure 1.3.4
Changes in Heating Oil Demand
000 m3/d

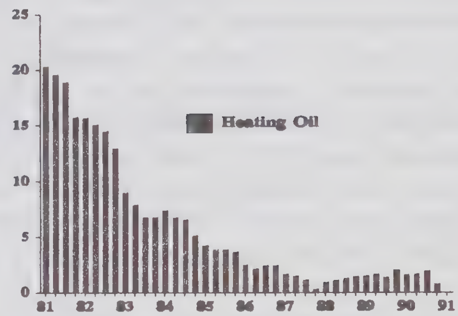


Figure 1.3.5
Changes in Heavy Fuel Oil Demand
000 m3/d

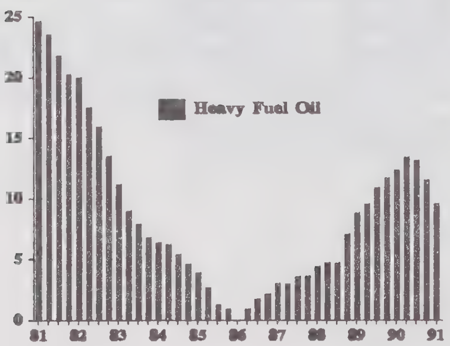
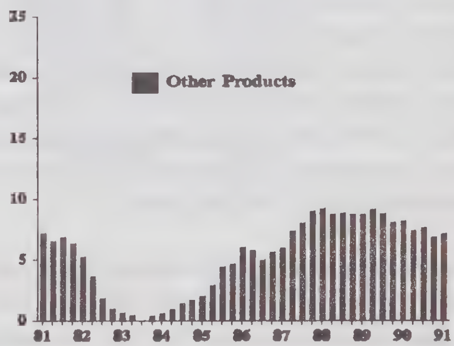


Figure 1.3.6
Changes in Other Products Demand
000 m3/d



1.4 A Comparison of Heating Oil Consumption and Degree Days

A basic tenet of physics is that the amount of heat energy required to maintain an enclosed space at a constant temperature rises proportionately with the difference between the inside and outside temperatures, other things being equal. Thus, if the temperature outside becomes 20% colder, or conversely, if the inside temperature is raised by 20%, the amount of fuel consumed would be expected to rise commensurately.

The implied linear relationship between fuel consumption and temperature differentials will not hold, however, when other things are not equal. Other weather parameters not captured in a comparison of temperature differentials and fuel consumption, such as the amount of radiant heat from the sun, precipitation (e.g. snow), and wind, all could influence the amount of fuel consumed.

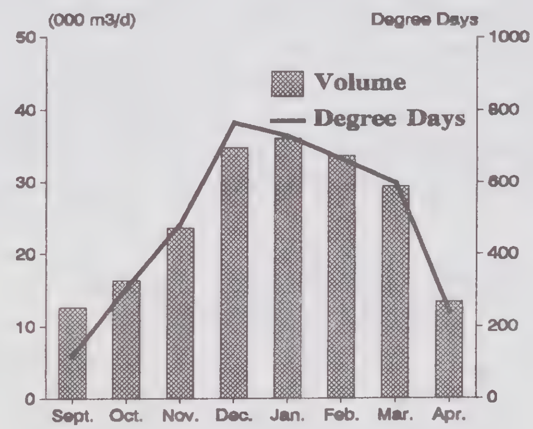
The figure below shows the close relationship between heating oil sales and monthly degree-day totals in Canada, averaged over the heating seasons of the last three years. Degree-days are the units of measurement of the differentials between mean daily outdoor temperatures, and the average indoor temperature which is assumed to be a constant 18^0 C. Months with a higher number of degree days are correspondingly colder. Since it is assumed that no heating oil is consumed when outdoor temperatures exceed the average indoor temperature, such instances are excluded (i.e. assigned a zero value) from the calculation of degree-days. This sets a common zero base for the two variables and thereby facilitates comparison.

A caveat: the average monthly volumes shown in the figure are often sales to local marketers and are thus only indicative of heating oil consumption in that they fail to distinguish between changes in stocks held by the marketers (or for that matter, by the end-users) and actual consumption.

This introduces a statistical reason for divergences to occur between degree-days and consumption. For example, sales in September are normally higher than they would otherwise be because marketers and end-users are in the process of rebuilding their inventories after these were partially drawndown during the May-to-August period.

It is also important to note that during the peak months of the heating season (i.e. January and February), sales of heating oil account for only about 15% of total product sales.

Figure 1.4.1
Heating Oil Sales vs Degree Days
(Three year Average)



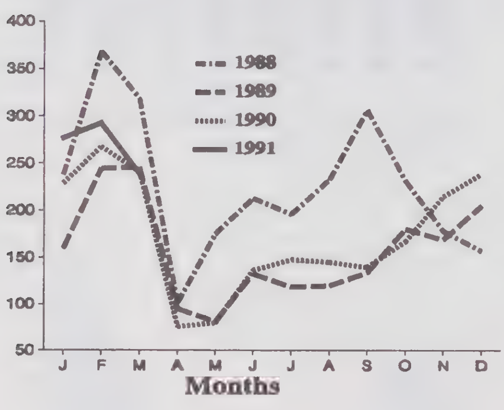
2. Drilling and Exploration Activity

. *The Canadian oil and gas exploration and development industry posted positive gains during the first quarter of 1991; however, the level of drilling activity is expected to fall below earlier expectations.*

Oil and gas drilling activity in western Canada during the first quarter of 1991 lived up to industry expectations with contractors experiencing their busiest winter in three years. However, despite this strong first-quarter performance the drilling industry, which has not recorded a profitable year since 1980, is expected to continue to remain depressed.

According to the Canadian Association of Oil Drilling Contractors (CAODC), 270 (or 56%) of 479 rigs were active during the first quarter of 1991 with drilling in January and February exceeding expectations. This high level of activity continued through to the middle of March when the spring break-up and resultant road bans began to restrict field activity.

Figure 2.1
Drilling Activity in Western Canada
(Number of Active Rigs)



This increase in drilling activity can be attributed to several factors, most notably the rise in crude oil prices as a result of the Persian Gulf conflict and to some catch up drilling by the industry which a year earlier was forced to curtail activity as a result of an early and prolonged spring break-up.

Most of the first-quarter increase was recorded in Alberta where the average number of active rigs increased to 205 of an available 365 from 185 of 378 rigs a year earlier. In British Columbia 42 rigs were reported operating compared with 38 while Saskatchewan averaged 19 compared with 15 the year before.

A first-quarter recovery in crude oil development and exploration drilling helped to push total well completions 16% higher than a year earlier. By the end of March, 1845 wells (including 612 dry wells) were completed with the total number of metres drilled up 30% to 2.2 million. In Alberta, well completions increased to 1435 from 1112 while metres drilled rose 23% to 1.7 million.

Of this total, development wells increased 23% to 916 wells. As illustrated in figure 2.2, most of this increase was the result of a 54% jump in successful oil completions. An 8% decrease in natural gas drilling may have been the result of overly optimistic industry export expectations, weak natural gas prices and a relatively mild winter.

Exploratory completions totalled 929, up 9% from the year before. Natural gas remained the favoured target of producers despite an 8% decrease in successful well completions. However, crude oil completions nearly doubled with most of the increased activity recorded in Alberta and Saskatchewan.

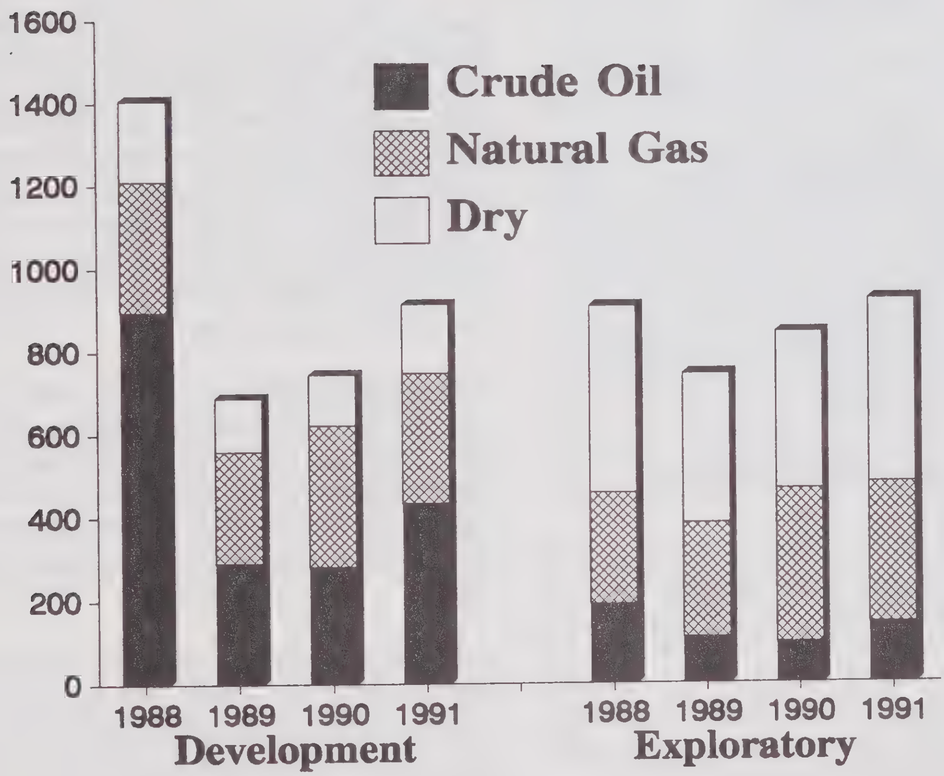
Drilling activity in 1991 is forecasted to fall short of earlier expectations. The industry is also expected to undergo a further reduction in the number of contractors and rigs. In fact, over the last five years the number of drilling companies has fallen from 80 to 52. Much of this industry pessimism is based on the post war weakening of natural gas and crude oil prices combined with rising operating costs.

The CAODC had forecast an average of 181 of 480 rigs operating in 1991. This level of activity would have represented a 10% increase over last year. However, based on a US$20 per barrel (WTI) average price, the association now forecasts a 3% increase in activity with 176 of 473 rigs operating.

Correspondingly, the total number of wells expected to be drilled this year has been reduced to 6000, down 200 wells from the previous forecast.

The association forecasts an average of 86 of 474 active rigs operating during the second quarter of 1991. However, by early June, the average number of active rigs had fallen somewhat below expectations with only 79 of 469 rigs reported active. Drilling during the third and fourth quarters is expected to rise to 150 and 201 of 470 available rigs.

Figure 2.2
Well Completions
(January to March)



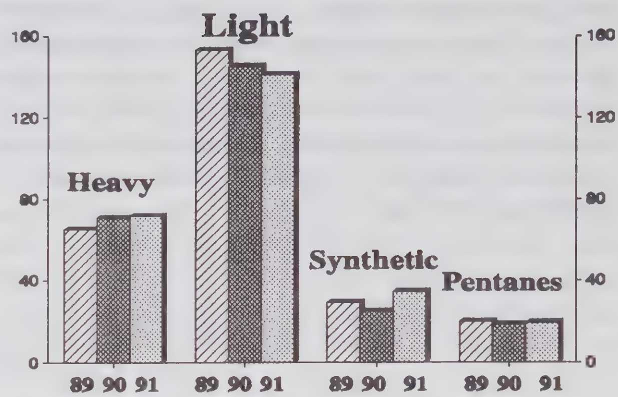
3. Crude Oil Supply

. *Canada produced 3% more crude oil and equivalent during the first quarter due to higher synthetic crude output.*

. *The post Gulf war collapse of crude oil prices forced some heavy oil producers to consider the shut-in of some heavy oil.*

. *Reflecting the downward trend in oil product consumption, crude oil imports levelled off in the first quarter, remaining virtually unchanged from the year before. A rise in imports into Quebec was offset by a decline in Ontario.*

Figure 3.2
Domestic Crude Oil Production
000 m^3/d



3.1 Total Crude Oil Supply

Total supply of crude oil and equivalent during the first quarter of 1991 averaged 366 000 m^3/d compared with 355 000 m^3/d a year earlier. Of this volume, domestic supply (including production from Ontario, recycled diluent, surplus Newgrade supply re-injected into the Interprovincial Pipe Line and inventory change) averaged 275 000 m^3/d compared with 264 000 m^3/d last year. Gross crude imports averaged 91 000 m^3/d unchanged from the year before. The equivalent of about 36% or 131 000 m^3/d of this total supply was delivered to the export market.

3.2 Domestic Crude Oil Production

Total domestic production of crude oil and equivalent during the first quarter of 1991 averaged 267 000 m^3/d. Despite a continuing decline in conventional light crude production, total production was 3% higher than the year before. Most of this increase was the result of a significant improvement in total synthetic crude output from Alberta's Syncrude and Suncor oil sands plants. Heavy crude production increased marginally.

Over the first quarter of 1991, the production of conventional light crude averaged 141 000 m^3/d. Although just below that of the previous quarter, production fell 4 000 m^3/d below a year earlier. As conventional production declines, the result of the ongoing depletion of conventional fields, its share of total light and equivalent supply has also fallen. Production during the first quarter represented about 72% of this volume compared with 77% during the same period a year earlier.

The decline in conventional light crude production, estimated by the National Energy Board at 5% per year, is expected to continue as new conventional light crude discoveries fail to replace production. This decrease, most of which occurred in Alberta, has been offset somewhat by an increase in total synthetic crude output.

Synthetic production averaged 35 000 m^3/d during the first quarter, up nearly 40% from a year earlier. Most of this increase was due to Syncrude's gradual return to near capacity after a disabling fire late in 1989. Total production is expected to continue to rise over the next few years with further debottlenecking of the existing oil sands plants and the scheduled start-up of a third plant in 1993.

Pentanes Plus or condensate production has remained relatively constant at about 20 000 m^3/d. Total available supply to refineries is dependent on demand for diluent which is associated with the production and pipeline delivery of heavy crude oil. Typically, about two thirds of pentanes supply is used as diluent for heavy crude blending with the remainder delivered as refinery feedstock.

During the first quarter, unblended heavy crude and bitumen supply (reduced by the CO-OP upgrader feedstock requirements) increased to 72 000 m^3/d, marginally higher than a year earlier. While production from Alberta's conventional fields appears to have stabilized, production from Saskatchewan has increased with the use of special enhanced oil recovery methods such as steam injection and horizontal drilling. Bitumen production held at about 22 000 m^3/d.

Although production and reserves additions of more valuable light crudes have been on the decline, western Canada still remains rich in heavy crude oil and bitumen potential. However, lower post Gulf war prices for heavy crudes have made production, according to some industry analysts "a break-even proposition or worse". Producers were particularly concerned with the wide price differential between light and heavy crudes.

Weak heavy crude prices have resulted in the shut-in of some expensive heavy oil wells. As a result of a large post war related surplus of heavy crude, analyst doubt that prices will strengthen during the summer - the peak season for asphalt demand. However, on the positive side, lower prices for heavy crude have improved the economics of heavy oil upgrading.

Based on National Energy Board estimates, 1991 domestic crude oil and equivalent production is expected to average 265 000 m^3/d with second-quarter output pegged at 258 000 m^3/d. Conventional light crude production is expected to continue to decline with synthetic crude output projected at or near capacity. Heavy crude and bitumen production is expected to record a modest gain on the strength of higher bitumen production.

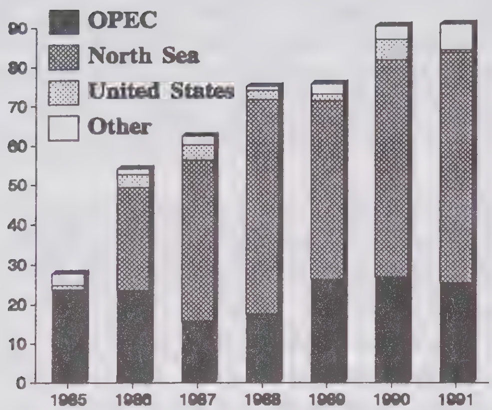
3.3 Crude Oil Imports

Reflecting declining refined product demand in eastern Canada, crude oil imports declined by about 1 000 m^3/d to 91 000 m^3/d in the first quarter of 1991, after having reached their highest quarterly level in almost a decade in the fourth quarter of 1990. On a year-over-year basis, imports were virtually unchanged from last year.

In the Atlantic region, which is dependent on foreign crude oil, imports rose marginally year-over-year to 51 000 m^3/d. Lower refinery throughtput (and sales) this year resulted in a build of crude oil inventories (as opposed to last year's first quarter drawdown). OPEC crudes, a little more than half of which came from Saudi Arabia, comprised 47% of total Atlantic deliveries. Saudi Arabia's relatively large share has resulted from the United Nations embargo on Iraqi crude since Iraq's invasion of Kuwait. North Sea crudes, mostly Norwegian, accounted for another 43% of the Atlantic total.

A 4 000 m^3/d rise in foreign crude oil deliveries to refineries in Quebec virtually matched the decline that occurred in Ontario. Quebec imports approached 40 000 m^3/d, making up almost 90% of the region's crude oil receipts. The increase from last year reflected the Montreal refiners' sudden shift away from domestic crudes towards imports in the previous quarter. North Sea crudes made up over 90% of the region's imports. They also accounted for all of this year's increase, which was not unexpected given the past import preferences of the Montreal refineries.

Figure 3.3.1
Imports of Crude Oil by Source
000 m³/d

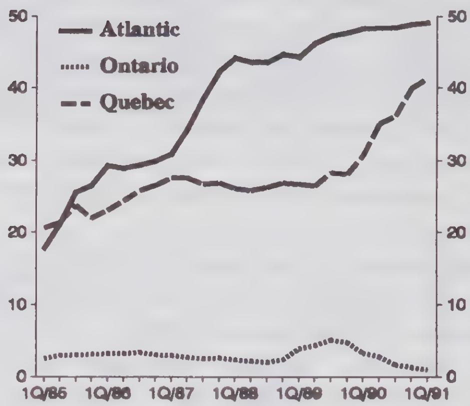


The decline in imports into Ontario, to below 1 000 m³/d, reflected several developments that arose either this year or last. Last year, Ontario refiners had increased their call on foreign crudes (entirely from the United States) to compensate for the shortfall in synthetic crude that arose in the wake of the explosion and fire at the Syncrude plant towards the end of 1989. This year, on the other hand, the downward shift in demand for domestic crude oil in Quebec has resulted in a surplus of Canadian crudes available to Ontario refiners. This surplus has only been made larger by a significant drop in crude oil demand in Ontario.

The figure 3.3.2 shows the regional trends in crude oil imports since 1985 when the Canadian oil market was deregulated. Atlantic refiners accounted for most of the increase in imports between 1985 and 1989. Initially, this reflected the substitution of imports for domestic crudes following deregulation. The upward shift in Atlantic imports that occurred in 1987 marked the re-opening of the Come-by-Chance refinery, which has been largely dedicated to refining imported crude oil for the export market. More recently, imports have been boosted by developments in Quebec.

When the de-activation of the Sarnia-Montreal extention is completed, the level of imports into Quebec is expected to further approach that in the Atlantic. In Ontario, imports could rise, or continue at their currently low level, over the next few years. Much will depend on trends in domestic light oil availability vis-a-vis demand in the region.

Figure 3.3.2
Crude Oil Imports by Region
000 m³/d



4. Crude Oil Disposition

. *In tandem with falling refined product sales, Canadian refiners sharply curtailed their demand for crude oil during the first quarter. Virtually all of the decline fell on domestic crudes with the level of imports holding steady from last year.*

. *Exports of crude oil and equivalent, representing about 50% of total crude oil production, increased dramatically during the first quarter primarily as a result of falling domestic demand for indigenous supply. Higher exports of conventional light crude accounted for most of this increase.*

4.1 Canadian Refinery Crude Oil Receipts

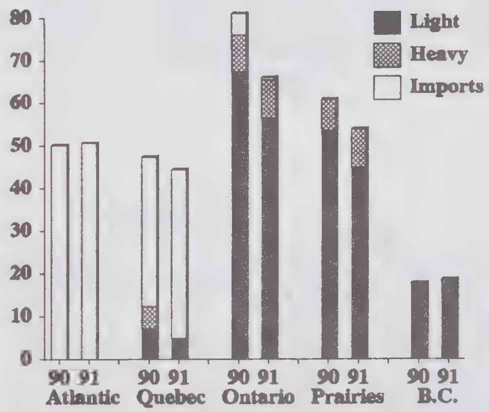
After the high level reached during the fourth quarter of 1990, crude oil deliveries to Canadian refineries fell by about 25 000 m^3/d to 234 000 m^3/d during the first quarter of 1991. In a year-over-year comparison, receipts were down by almost as much, falling by 24 000 m^3/d. A drop in domestic crude oil deliveries to 143 000 m^3/d accounted for all the decline. Crude oil imports were virtually unchanged at 91 000 m^3/d.

Regionally, the decline was confined to central Canada and the Prairies, there being actually slight increases in the volumes of crude delivered to Atlantic and British Columbia refineries. The increase in the Atlantic was of no particular significance, apart from the fact that it led to a substantial crude oil inventory build as opposed to last year's drawdown. In B.C., the increase helped boost product exports. Ontario saw the largest drop in receipts, with deliveries down 15 000 m^3/d from the year before.

The overall decline in crude oil demand was in response to the sharp downturn in refined product sales in the domestic market which started early in the fourth quarter of 1990 and continued through the first. Reduced receipts and crude runs were also to correct an inventory surplus that had developed in the fourth quarter. Refiners had failed to anticipate the severity of the slump in product demand and were left with excessive inventories of both crude oil and refined products at the end of the year.

Since there happened to be a commensurate drop in refined product demand in Canada in the first quarter, the excess of oil stocks could only be reduced through a 9 000 m^3/d increase in product exports, and through displacement of over 8 000 m^3/d worth of product imports. In effect, the substantial improvement in Canada's net trade position in refined products from the year before helped offset about two-thirds of the decline that would have otherwise occurred in domestic refiners' sales.

Figure 4.1
Refinery Crude Oil Receipts by Region
000 m^3/d



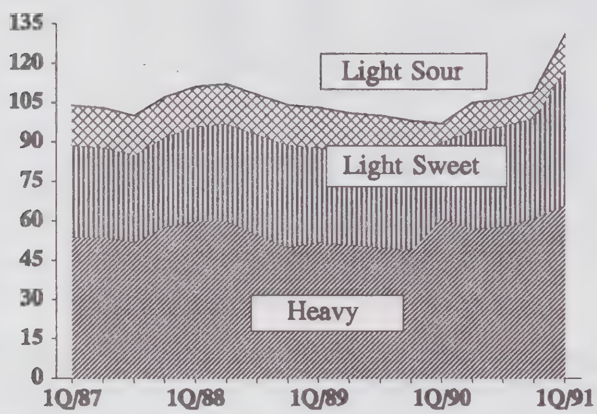
Moreover, the drop in crude oil demand occurred at a time when refineries would normally be in the process of raising their feedstock and throughput levels in order to buffer product supplies prior to maintenance turnarounds which temporarily hinder or halt refinery operations in the spring. It would appear that another, likely more important, reason for this year's decline was because refiners anticipated a continuation of the slump in product demand during the second quarter and did not want to be caught with another inventory overhang. This is suggested by the change in the level of refined product inventories this year relative to last. Last year, when sales were relatively high, inventories were built at a rate of 14 000 m^3/d during the first quarter, reaching 12.8 million m3 by the end of the period.

This year, by contrast, stocks were drawndown by almost 3 000 m^3/d to 11.6 million m^3, suggesting that refiners expected to be able to cope with product demand during the turnaround period even with substantially lower inventories.

4.2 Crude Oil Exports

Crude oil exports during the first quarter of 1991 averaged 131 000 m^3/d, almost 35 000 m^3/d or 36% more than a year earlier. This jump was the result of a modest increase in domestic crude supply combined with a sharp drop in demand for indigenous crudes by domestic refiners. Exports in February reached a 145 000 m^3/d, half of which were light crude oils.

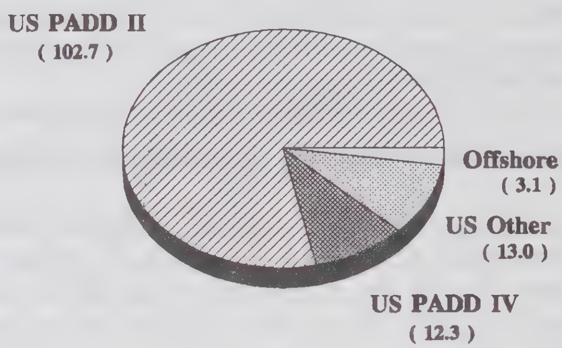
Figure 4.2.1
Crude Oil Exports
000 m^3/d



Crude exports represented about 50% of Canadian production (78% of blended heavy supply and 36% of net light crude supply), compared with 37% last year. Exports of light crudes reached 65 000 m^3/d compared with 35 000 m^3/d a year earlier. Most of this increase was the result of a near doubling of conventional light exports. Heavy crude exports increased 8% to 66 000 m^3/d.

As illustrated in Figure 4.2.2, most Canadian crude oil exports are delivered to the United States with about three quarters of this volume typically delivered to U.S. PAD District II, Canada's largest export market.

Figure 4.2.2
Crude Oil Exports by Destination
(First Quarter 1991)
000 m^3/d



During the first quarter of 1991 small volumes of mainly heavy crude were shipped offshore through the port of Vancouver (via the Trans Mountain Pipe Line and the Westridge Marine Terminal) to South Korea and Taiwan. No offshore exports were shipped through the port of Montreal, in fact, none have been reported since the fourth quarter of 1989.

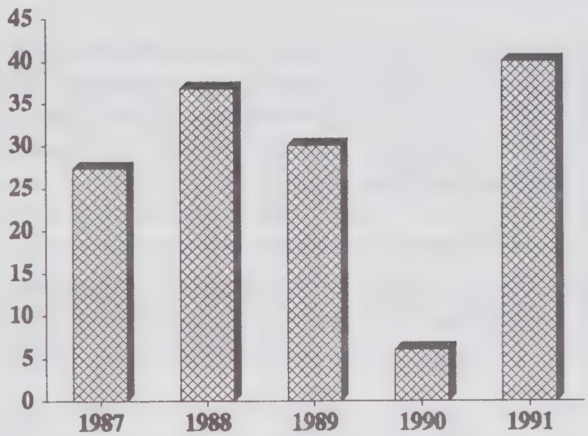
Most of this first-quarter increase in exports was the result of a 48% jump in deliveries to PAD District II for an average of 102 000 m^3/d. Of this volume, deliveries to the Chicago refining area doubled to 70 000 m^3/d. Deliveries of light crude tripled to 41 000 m^3/d while heavy crude receipts increased by 35 % to 29 000 m^3/d. All other U.S export destinations including Canada's second largest market, PAD District IV (the Montana/Wyoming area), increased their take of Canadian crude marginally.

Canada's net crude oil export position has been on the decline since 1988. However, as a result of the drop in domestic demand, Canada's first-quarter net export position increased significantly compared with the same period last year. As illustrated in figure 4.2.3, crude exports exceeded imports by 40 000 m^3/d compared with 6 000 m^3/d a year earlier - a period of comparatively high refinery demand.

Crude oil exports are expected to fall to about 120 000 m^3/d over the remainder of 1991. Nevertheless, at this level, exports would still be substantially above that recorded over the last fifteen years. Light crude exports are expected to account for much of this strength although heavy crude will still account for more than half of this total.

Given that domestic crude oil production is expected to remain virtually unchanged, the volume of crude available for export will most likely be determined by the extent of the drop in demand for indigenous crude in the Canadian market. This in turn will reflect the domestic downturn in demand for refined petroleum products, and the closure of the Sarnia to Montreal portion of the Interprovincial Pipe Line.

Figure 4.2.3
Net Crude Oil Export Position
(First Quarter)
000 m^3/d



5. Pipelines Deliveries

. *Trans Mountain Pipe Line has scaled down its proposed deep water port-and-oil pipeline project across the Puget Sound.*

. *Canadian crudes are now regarded by Montreal refiners as being generally uncompetive with offshore crude. This factor has led to a reduction of total throughput on IPL'S Sarnia-Montreal extension and its closure.*

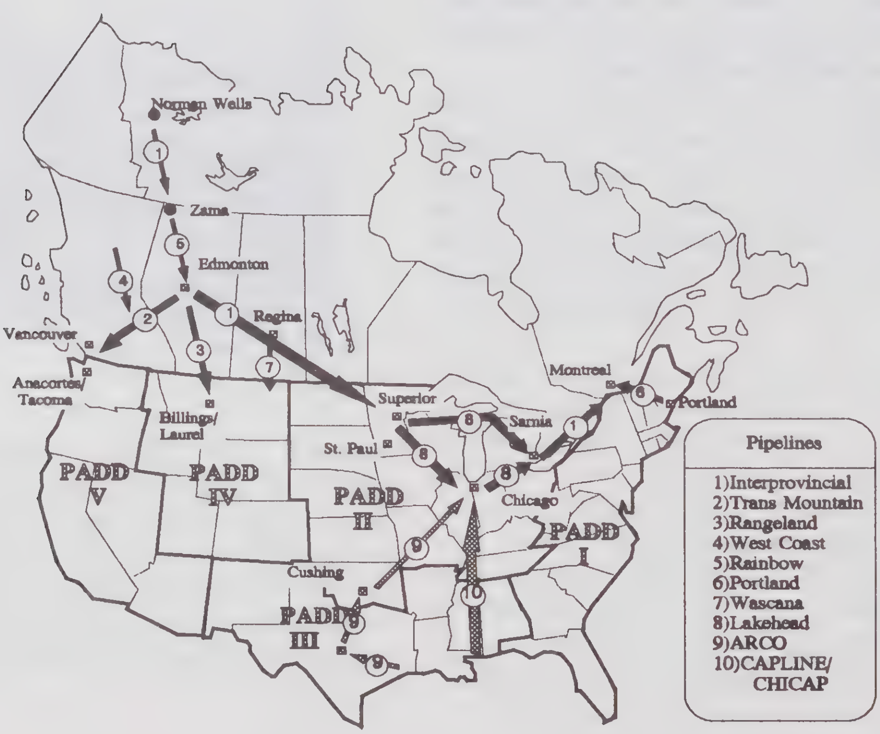
Most Canadian crude oil is gathered at Edmonton, Alberta. It is then delivered to the domestic and export market, for the most part, by a network of pipelines.

The bulk of Canadian exports are delivered to the United States, via the Interprovincial and Lakehead pipeline systems. Smaller volumes are delivered by the Trans Mountain Pipe Line to the west coast for shipment to U.S. refineries and tankering offshore. The Rangeland pipeline supplies U.S. refiners south of Edmonton.

Canadian crude competes in the U.S. midwest, in particular, in the Chicago refining area, with indigenous U.S. crudes and other foreign crudes delivered directly through the CAPLINE/CHICAP pipeline system from the Louisiana, Gulf Coast and alternatively the Arco pipeline system from the Texas, Gulf Coast via Cushing Oklahoma.

Figure 5.

Major Crude Oil Pipelines



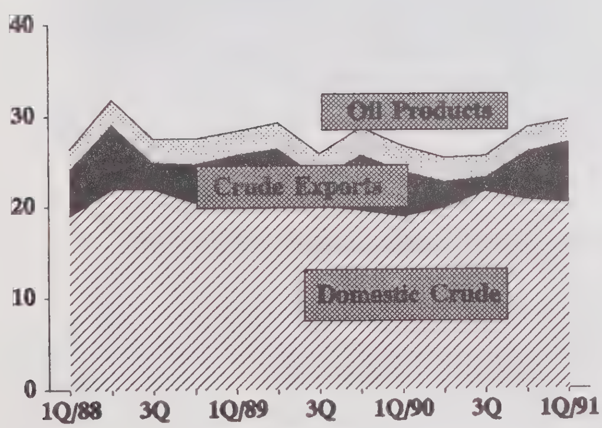
5.1 Trans Mountain Pipe Line Deliveries

Trans Mountain Pipe Line (TMPL) deliveries during the first quarter of 1991 averaged 30 000 m^3/d. Total deliveries of crude oil and product were 3 000 m^3/d higher than last year's average. Most of this increase in throughput was the result of a near doubling of crude exports to 7 000 m^3/d while domestic deliveries of crude and product held at about 23 000 m^3/d.

Although domestic deliveries of crude oil and product were down somewhat from the previous quarter, first-quarter deliveries of crude at 15 000 m^3/d remained relatively unchanged from last year. Deliveries of semi-refined products held at about 6 000 m^3/d while deliveries of refined products to Kamloops, British Columbia remained at just over 2 000 m^3/d.

Crude oil deliveries for export by tanker through the Westridge Marine Terminal averaged 6 000 m^3/d. Pipeline exports from Sumas to refineries in the Puget Sound area of Washington State remained relatively unchanged at about 1 000 m^3/d. Heavy crude accounted for over 80% of total exports.

Figure 5.1
Trans Mountain Pipe Line Deliveries
000 m^3/d



Trans Mountain Pipe Line has scaled down its proposed deep water port-and-oil pipeline project across the Puget Sound.The company concluded after meeting with shippers that exports of heavy crude would be limited to seasonal spot sales in the foreseeable future.

TMPL's proposed project includes a common-use offshore terminal near Low Point on the Olympic Peninsula and a connecting pipeline system for shipment of Alaska and foreign crude oil to the four large U.S. refineries located at Anacortes, Ferndale and Cherry Point in Washington State. The company had also proposed exporting Alberta crude oil through its U.S. extension that already serves these refineries with the construction of an 'out-bound' pipeline to the offshore terminal.

Eliminating the 'out-bound' line from the Low Point project is expected to reduce the total project cost from US$515 million to US$435 million. TMPL is expected to file application with the Washington State Energy Facilities Evaluation Council in November. The state review process is expected to be completed late in 1992 and if approved the project should be operational by the end of 1994.

5.2 Interprovincial Pipe Line Deliveries

The Interprovincial Pipe Line (IPL) system, one of the largest pipelines in the world consists of three major sections stretching some 3 700 km from Edmonton, Alberta to Montreal, Quebec.

The western section originates at Edmonton travels east through Regina, Saskatchewan and crosses into the United States near Gretna, Manitoba. The Lakehead Pipe Line Company (a wholly owned IPL subsiduary) operates the American portion of the line which serves markets in the U.S. Great Lakes area. The eastern section from Sarnia to Montreal provides for the delivery of western Canadian crude to eastern markets.

In the summer and fall of 1990, as illustrated in figures 5.2 and 5.3, in response to economic forces, Montreal refiners began to reduce receipts of Canadian crude oil delivered by the IPL system. Throughput on the extension began to decline as Canadian light sweet crudes delivered to Montreal became generally uncompetitive with offshore crude. As well, lower throughputs resulted in greater scheduling problems and higher line fill costs for shippers. This prompted them to advise IPL that they intended to terminate deliveries of Canadian crude to Montreal during the first quarter of 1991. As a result of shippers intentions, IPL began to plan for line idling and deactivation.

Coincident with these developments was the invasion of Kuwait by Iraq in August of 1990 which led to war in January 1991. As tensions in the Persian Gulf heightened and the possibility of supply disruptions became a concern, the Minister of Energy, Mines and Resources Canada, suggested to shippers that the pipeline be kept operational for the heating season. The Minister also instructed the National Energy Board (NEB) to review and report on the prospects for, and implications of, the closure of the Sarnia-Montreal pipeline and the options available for maintaining the line in an operating mode.

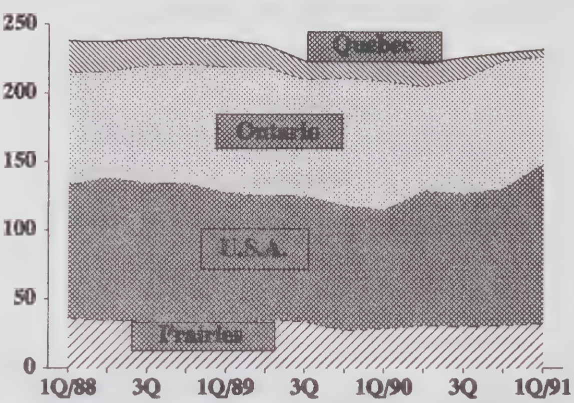
On July 5, 1991 the NEB's report titled 'The Sarnia-Montreal Pipeline, A Review and Report By the National Energy Board' was released. In summary, the NEB concurred with shippers that Canadian crudes delivered to Montreal were not competitive with offshore crude, primarily as a result of long delivery times and high inventory costs. The NEB also determined that there was no immediate security of supply reasons requiring federal government intervention to keep the line operating between Sarnia and Montreal.

In conclusion the NEB study recognized that current market conditions were different from those of 1976. At that time supply considerations were a major factor in the decision to build the Sarnia-Montreal pipeline extension. The NEB recognizes that the current closing of the line is strictly a commercial decision.

Total IPL (including Sarnia-Montreal) and Lakehead deliveries of crude oil and other hydrocarbons, including petroleum products and natural gas liquids, during the first quarter of 1991 averaged 234 000 m^3/d compared with 229 000 m^3/d during the previous quarter and 226 000 m^3/d a year earlier.

First-quarter deliveries to Canadian refineries fell to 115 000 m^3/d compared with 141 000 m^3/d last year. Deliveries to Ontario and Quebec were down 20% and 72%, respectively. This 25 000 m^3/d decline in domestic deliveries was offset by a 33 000 m^3/d increase in exports to the United States. Deliveries to U.S. destinations averaged 119 000 m^3/d compared with 86 000 m^3/d during the first quarter of last year. As a result, domestic deliveries now account for 50% of total IPL throughput compared with 62% a year earlier.

Figure 5.2
Interprovincial Pipe Line Deliveries
000 m^3/d



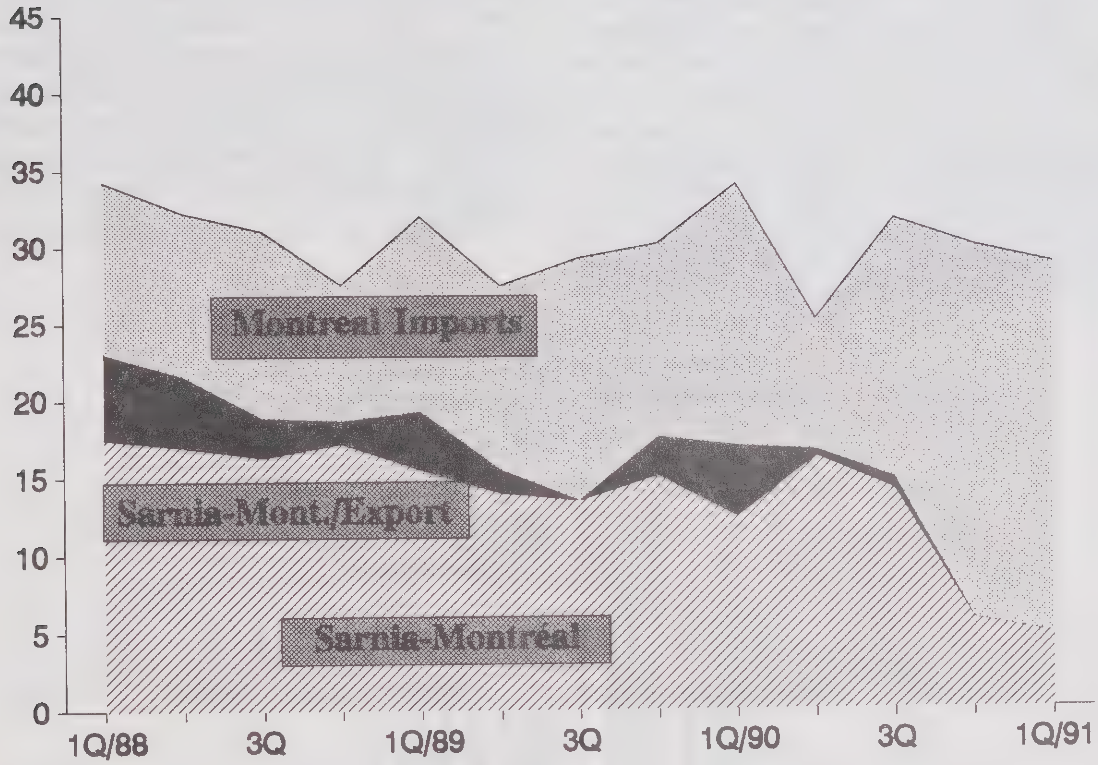
5.3 Pipeline Deliveries to Montreal

Total deliveries of crude oil and equivalent (foreign and domestic) to Montreal refiners during the first quarter of 1991 averaged 29 000 m^3/d. Although deliveries were relatively unchanged from both the previous quarter and the corresponding period last year the sourcing of these receipts changed significantly.

With the announced closure of the Sarnia-Montreal pipeline, as discussed in the previous section, Montreal refiners have become increasingly reliant on imported feedstock. Domestic deliveries during the first quarter fell 8 000 m^3/d below a year earlier to about 5 000 m^3/d. This drop was nearly matched by a 7 000 m^3/d increase in crude oil imports. Imports averaged 24 000 m^3/d with most of this volume delivered from the North Sea via the Portland-Montreal Pipe Line.

IPL expects that the last barrel of crude in the Sarnia-Montreal line to be delivered by the end of June. The pipeline will then be filled with nitrogen. The line will however remain available for use after the purging operation. Regulatory procedures require IPL to formally request NEB approval for deactivation if the company determines that there is likely to be no resurgence of interest in moving crude from west to east in the next twelve months.

Figure 5.3
Deliveries to Montreal
000 m^3/d



6. Refinery Throughput and Utilization Rates

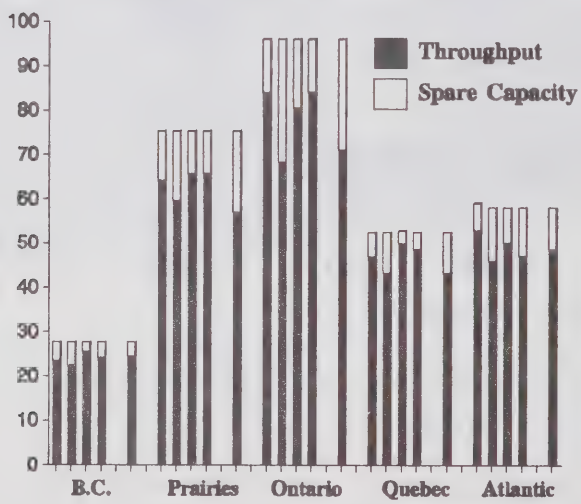
. *The national refinery utilization rate averaged about 79% during the first quarter. The utilization rate was highest in British Columbia and lowest in Ontario.*

Refinery throughput will normally diverge from refinery crude oil receipts for two reasons. First, feedstocks other than crude oil are also charged in the refining process. Some of the 'other' feedstocks include gas plant butanes (used mostly by Prairie refineries) and partially processed oil (used mostly by B.C. refineries). During the first quarter of 1991, these 'other' receipts averaged 12 000 m^3/d or about 5% of total refinery throughput in Canada. Second, refinery throughput reflects changes in feedstock inventories. Other things being equal, an inventory drawdown will cause refinery throughput to exceed receipts - and vice versa in the case of an inventory build. Over the quarter, crude oil inventories at the national level were built at a rate of more than 1 000 m^3/d.

Total throughput averaged 246 000 m^3/d during the first quarter, almost 26 000 m^3/d below the same quarter the year before. With estimated Canadian refining capacity now up by about 4 000 m^3/d to almost 310 000 m^3/d, (due to capacity expansions last year at refineries in Quebec and the Prairies), this level of throughput corresponded to a national refinery utilization rate of about 79%. The utilization rate was highest in British Columbia where it reached 89%, and lowest in Ontario, at 74%. The figure below illustrates refinery throughput and capacity by region, starting from the first quarter of 1990.

A small 2 900 m^3/d refinery in Taylor, British Columbia is scheduled to close by July, 1991. The refinery commenced operations in 1957 and has been used largely to supply transportation fuels and asphalt to the northeastern part of the province. These products will now be shipped in from a refinery in Edmonton. This will be the first refinery to close since a spate of refinery closures occurred in the early to mid-eighties.

Figure 6.1
Refinery Utilization vs Capacity
(1st Quarter 1990 to 1st Quarter 1991)
000 m^3/d



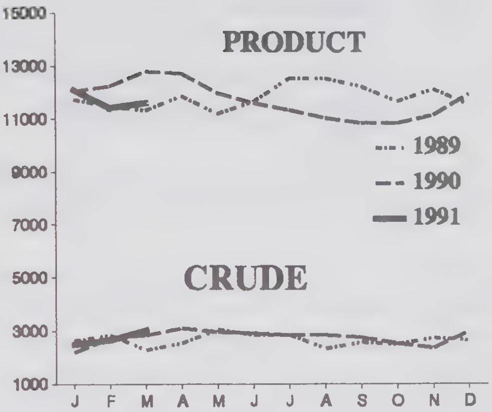
7. Stocks

. *Stock build which normally occurs in the first quarter of the year failed to materialize as a result of moderate drawdown in petroleum product inventories.*

Primary stocks of crude oil and refined products closed the first quarter of 1991 at 14.7 million m^3. Although marginally below the close of the previous quarter, stocks were down 6% from that recorded a year earlier. Refined products, accounting for 11.6 million m^3 of this total, were down 9% from the previous year. Crude oil stocks recorded a 6% increase to 3.0 million m^3.

Most of the first-quarter decrease reflected a sharp recession driven drop in demand for refined petroleum products combined with a relatively mild winter and competition from alternative fuels such as natural gas. Stocks of crude oil, although somewhat higher, remained within normal refinery operating levels.

Figure 7.1
Crude Oil and Petroleum Product Stocks
million m^3



As illustrated in table 7.1, all regions adjusted their stock levels. However, most of the first quarter year-over-year change occurred in Ontario where crude oil and refined product stocks fell 33% below that recorded a year earlier. Stocks were also 25% below the close of the previous quarter.

Table 7.1

Closing Crude and Petroleum Product Inventories

(End of March)
000 m^3

	Crude			Product		
Year	1989	1990	1991	1989	1990	1991
Atlantic	676	1044	1340	1900	2130	1760
Quebec	783	737	826	2222	2454	2547
Ontario	547	667	440	3487	4030	3327
Prairies	218	324	336	2554	3012	2742
B.C.	70	88	94	1171	1179	1247
Canada	2294	2860	3036	11334	12805	11623

Stocks of 'main' petroleum products, representing about 72% of total product inventories, closed the first quarter at 8.4 million m³, down 7% from a year earlier and 3% from the previous quarter. The 'other' petroleum products which includes such items as jet fuel, petrochemical feedstock and asphalt totalled 3.2 million m³, fell 15% from last year but remained relatively unchanged from the close of the previous quarter.

Figures 7.2, 7.3 and 7.4 illustrate the end-of-month stock levels for selected refined petroleum products.

By the end of March, stocks represented about 66 days of forward supply, three days fewer than a year earlier. If the Atlantic region is excluded from the calculation because a large portion its supplies are exported and the region is not connected by pipeline to domestic supplies the number of days of supply would be reduced to 60 days.

Stocks referred to in this section do not include estimates of crude oil held in pipeline tankage. If these stocks were included it is estimated that the number of days of forward supply would increase by about seven days.

Figure 7.2
Motor Gasoline Stocks
million m³

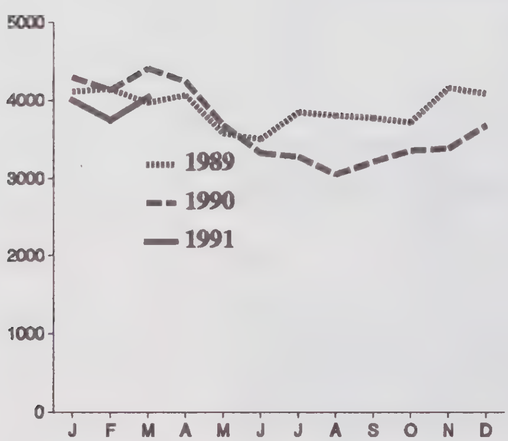


Figure 7.3
Middle Distillate Fuel Oil Stocks
million m³

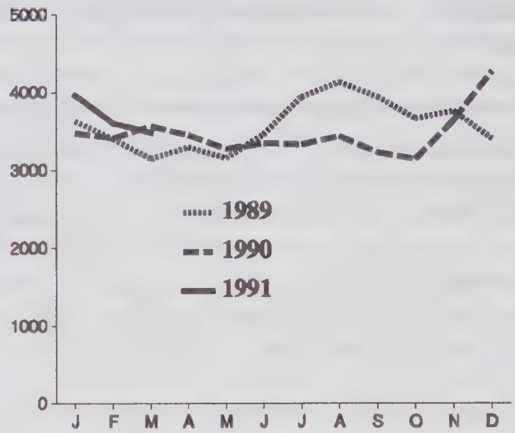
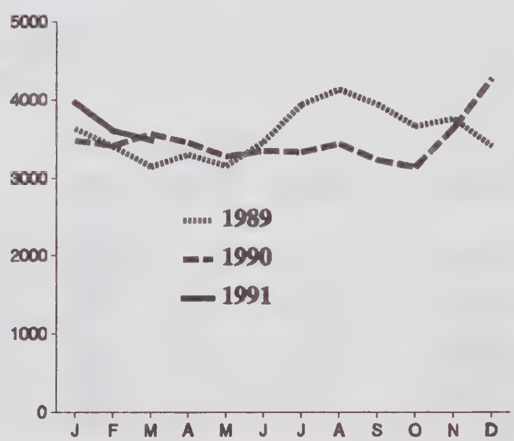


Figure 7.4
Heavy Fuel Oil Stocks
million m³



m₃

8. Crude Oil and Petroleum Product Prices

- *International and domestic crude oil and product prices collapsed shortly after the onset of hostilities in the Persian Gulf.*

- *Price differentials between Canadian Light, sour and heavy crude continued to increase as a result of oversupply and weak demand.*

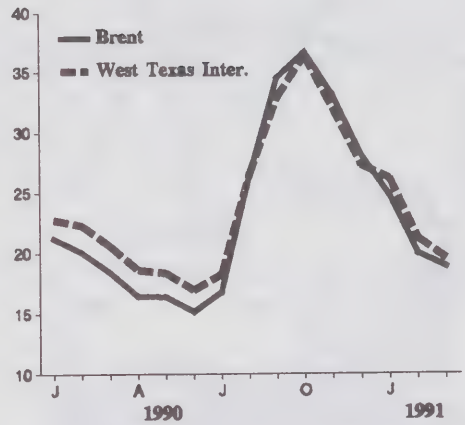
8.1 International Crude Oil Prices

Spot crude oil prices were extremely volatile over the first quarter of 1991. In early January, crude oil prices were relatively weak due to lower oil demand stemming from slower economic activity in industrialized countries (primarily the United Kingdom and the United States), increased conservation efforts, and a well-supplied oil market. However, as hostilities in the Persian Gulf escalated, crude oil prices strenghtened, as they responded to rumours and speculation emanating from the Gulf rather than to oil supply/demand fundamentals.

Once the war in the Persian Gulf actually started, the result was a record one-day dive in prices. WTI closed at $21.45/bbl on January 17, down $11.05/bbl from the previous day's $32.50/bbl, while Brent crude closed at $19.70/bbl, a decrease of $10.85/bbl. The collapse in crude oil prices reflected the initial market reaction to the success of the allied forces' action on Iraq, the perceived low risk to future oil supplies from the Persian Gulf, the high level of unsold producer oil stocks and the IEA's decision to invoke its contingency plan.

After the ceasefire in the Persian Gulf, crude oil prices began to firm, as most market analysts believed that OPEC would revert to crude oil production controls when the Market Monitoring Committee (MMC) met on March 11. Crude oil prices moved steadily downwards, however, as OPEC agreed to cut the production ceiling by only 200 MB/D, to 22.3 MMB/D. WTI averaged $22.35/bbl over the first quarter of 1991, up $0.45/bbl above first quarter 1990 levels. Nevertheless, this marked a dramatic decline from the fourth quarter of 1990, when WTI averaged $31.95/bbl.

Figure 8.1
International Crude Oil Prices
US$/barrel



8.2 Domestic Crude Oil Prices

During the first quarter of 1991, Canadian Par crude averaged $23.91/bbl, a decrease of $12.00/bbl from the fourth quarter of 1990. The decrease in domestic prices reflects a similar collapse of prices on international markets following the outbreak of war in the Persian Gulf in January. The success and intensity of the allied effort in the early days of the war prompted oil traders to speculate that the war would be short-lived and crude oil prices would quickly return to pre-crisis levels.

Figure 8.2.1 illustrates the close relationship between the price of Canadian Par crude oil and the U.S. benchmark crude oil, West Texas Intermediate (WTI).

The differential between Canadian Par and WTI NYMEX prices, on a calendar basis in Chicago, is illustrated in figure 8.2.2. The average differential observed in the first quarter of 1991 was US$0.34/bbl in favour of the U.S. crude, compared to an average $0.14/bbl in the fourth quarter of 1990.The increase reflects a return to a more traditional differential observed prior to the price gyrations during the Persian Gulf crisis.

Figure 8.2.1
Canadian Par Crude vs WTI (NYMEX)
at Chicago US$/bbl

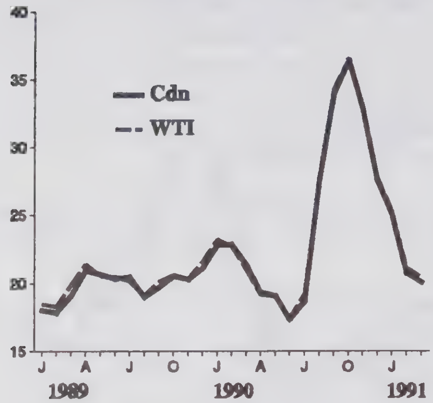


Figure 8.2.2
Canadian Par vs WTI (NYMEX)
Differential at Chicago

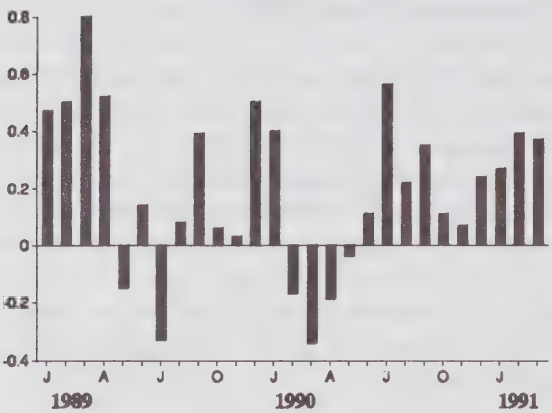
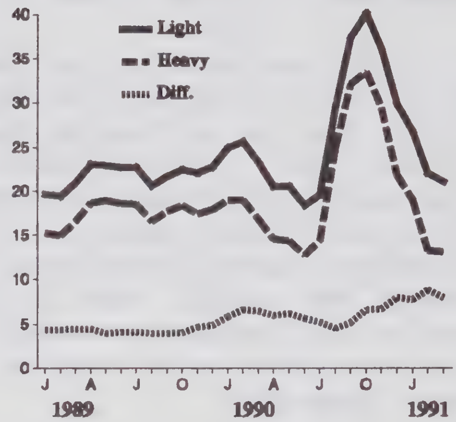


Figure 8.2.3 compares actual prices for Alberta light and heavy crude oil, purchased for use in Canada at main trunk line injection stations. On average reported light conventional crude oil quality for the first quarter of 1991 was 37.5°API, 0.43% sulphur and blends of heavy crude were 24.8°API, 2.44% sulphur. The differential between light and heavy crude oil prices during the first quarter of 1991 was $8.19/bbl, $1.07/bbl higher than the fourth quarter 1990.

The increase in the differential can be attributed to normal seasonal weak demand and the continued oversupply of heavy crude oil on the international market.

Figure 8.2.3
Comparison of Domestic Light
and Heavy Crude Oil
(Actual Alberta Purchase Price)
Can$/bbl



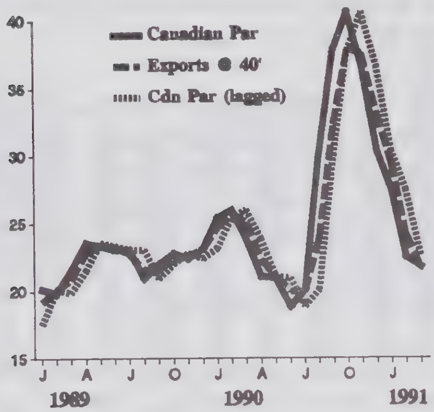
8.3 Export Prices

Figures 8.3.1 and 8.3.2 illustrate the relationship between light crude oil export prices and domestic prices.

Prices of light crude oil exported to the United States via the IPL system were netted back to Edmonton and adjusted to 40°API, on a stream by stream basis. These prices were then compared to Canadian Par crude prices, also at Edmonton.

As can be observed in figure 8.3.1, in a period of declining prices, exports would appear to be more expensive than Par crude for the same month; and, in a period of increasing prices, exports would appear to be cheaper. An evaluation on that basis alone would be misleading. Canadian Par crude prices were therefore "lagged" one month to normalize for differing delivery times and possible data collection problems.

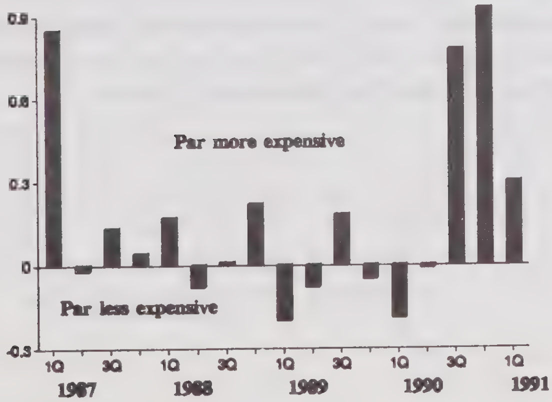
Figure 8.3.1
Export vs Canadian Par Crude Prices
$/bbl



For comparison purposes, an average of the current month's Par crude and its lagged price was calculated. Figure 8.3.2 illustrates the differential between this composite average Par crude and the average export price.

The reduced differential in the first quarter of 1991 reflects the return to crude oil prices observed prior to the Persian Gulf crisis.

Figure 8.3.2
Export vs Canadian Par
Price Differential
$/bbl



8.4 Canadian Crude Oil Price Differentials

Figures 8.4.1 and 8.4.2 illustrate the differentials between the prices of Canadian Par crude oil, bitumen and Alberta Light Sour crude oil.

Figure 8.4.1
Canadian Par vs Bitumen Prices
$/bbl

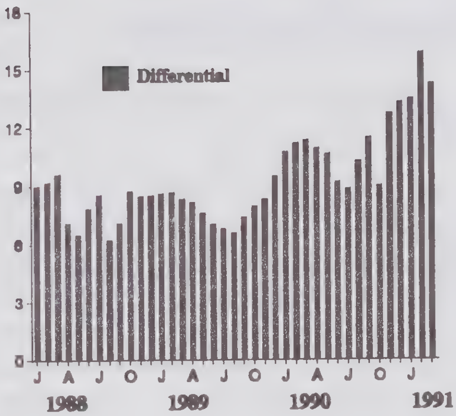
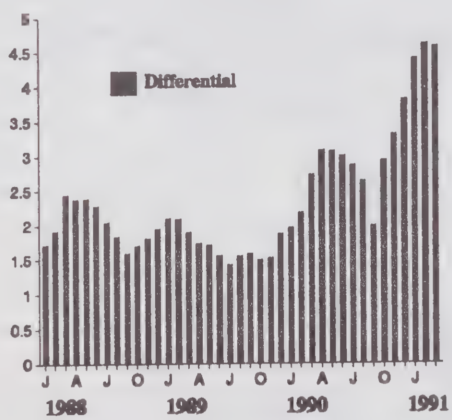


Figure 8.4.2
Canadian Par vs Alberta Light Sour Prices
$/bbl



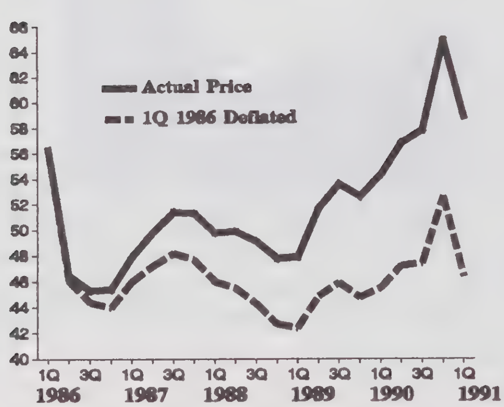
In the first quarter of 1991, the average Canadian Par to bitumen price differential increased $2.84/bbl to $14.55/bbl. Similarly, the average Par to Light Sour price differential increased $1.18/bbl to $4.53/bbl. These increases reflect continued oversupply and weak demand for sour and heavy crudes in both the domestic and international markets resulting from the Persian Gulf crisis. A number of other factors, such as high inventories, weak seasonal demand and high prices also combined to increase price differentials.

8.5 Petroleum Product Prices

Price Trends (Gasoline, Diesel and Residential Furnace Fuel Oil)

The two salient features of gasoline prices during the first quarter of 1991 were the initially high prices and the dramatic decline that followed. At the begining of January 1991, the average price of regular unleaded gasoline (self-serve outlets) was 65.7 cents per litre, a continuation of the trend toward high prices that began in November 1990 when the crisis in the Persian Gulf heightened. These gasoline prices were the highest ever recorded. A rapid decline in prices began in January and by March 1991 prices had fallen by about 10 cents to 54.2 cents per litre. The January 1991 price was 10 cents per litre or 18.6% higher than the average in January 1990.

Figure 8.5.1
Regular Unleaded Gasoline Prices
(10 City Average)
cents per litre



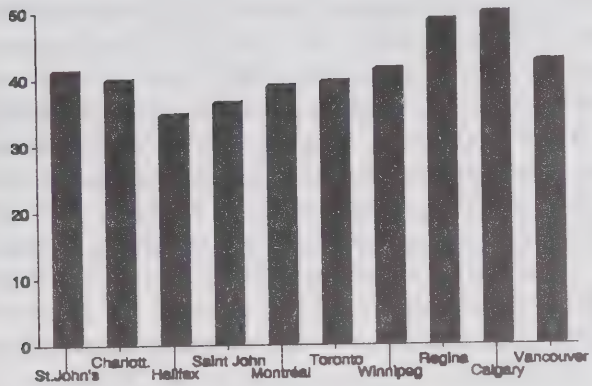
At 59 cents per litre, the average price for the quarter was about 6 cents per litre lower than the average during the previous quarter. The tax-included regular unleaded gasoline price for the first quarter 1991, when adjusted for inflation, declined almost 10 cents per litre or 18% over the last five years.

At the end of the first quarter of 1991 crude costs (19.0 cents per litre) had decreased 6.9 cents per litre from 25.9 cents per litre in December 1990. A decrease in federal taxes was partially offset by an increase in provincial taxes, the net result being a marginal tax decrease of 0.1 cents per litre over December 1990. The retail margin fell 0.1 cent per litre.

Diesel prices reached their highest level ever for the first quarter of 1991, increasing one cent per litre from the previous quarter (60 cents per litre in 1Q 1991 Vs. 59 cents per litre in 4Q 1990). Like gasoline prices, diesel prices rose rapidly during the Persian Gulf crisis (4Q 1990), but lagged behind gasoline prices by about a month. This is partly attributable to the relative sizes of the two retail markets. Similarly, when gasoline prices began to fall in the first quarter 1991, diesel prices followed the trend with a one month lag.

Residential furnace fuel oil prices gradually declined throughout the first quarter of 1991, dropping from a high of 46.8 cents per litre during January to 38.7 cents per litre at the end of March. Furnace fuel oil, which had been exempt from federal taxes prior to 1991, was subject to a 7% federal Goods and Services Tax on January 1, 1991. The effect of the new federal tax was an average price increase of three cents per litre. Warmer than normal temperatures and higher product prices caused the demand for heating oil to plunge, particularly in central and eastern Canada.

Figure 8.5.2
Average Consumer Furnace Oil Prices
(End of March)
cents per litre



Highlights in Regional Markets

Toronto - The Toronto market is the most volatile among the thirteen Canadian cities that are surveyed by Energy Mines and Resources on a weekly basis. In February and March 1991 prices reached as low as 46.6 cents per litre from a high of 65.1 cents per litre on January 1, 1991. Volatility in the Toronto market could be explained by the stiff competition that exists within the retail population of a large market. Retailers seeking ways to capture a larger share of the market by lowering prices find U.S. gasoline imports advantageous.

In response to falling crude costs during the first quarter of 1991, gasoline prices began to fall faster in the U.S. than in Canada. Due to differences in accounting methods, the flowthrough of crude cost changes to the customer is faster in the U.S. than in Canada. Canadian independent retailers imported lower priced gasoline from the United States and were able to price their product lower than their Canadian competitors. High inventory levels and low demand also contributed to falling gasoline prices.

Regina - For the third consecutive quarter, consumers in Regina benefitted from gasoline price wars. In December 1990, a committee of consumer and industry groups was set up in Saskatchewan to monitor gasoline prices and facilitate a greater public understanding of gasoline marketing. Statistics collected by the committee illustrated that Regina's gasoline retail outlets had a higher average sales volume than Saskatoon and other Saskatchewan cities. Regina, therefore, had more revenue per station which may support a low margin - high volume strategy of marketing. The average number of residents per station in Regina was 1655 whereas it was 1380 in Saskatoon.

Calgary and Edmonton - The gasoline market in both Calgary and Edmonton was characterized by raging price wars during the first quarter of 1991. Prices bottomed out in February and March at 39 cents per litre, the lowest in the country. Lower crude oil prices and falling demand began influencing gasoline prices in February and continued to do so during the balance of the first quarter of 1991.

In October 1990, a six-member committee (The Gasoline Consumers' Information Committee) was set up in Alberta to monitor gasoline prices. The committee's findings were published in a report released in December 1990. The report comprises of answers to questions most frequently asked by consumers about gasoline marketing in Alberta. Many of the questions are about the components that make up the price of gasoline and how they have changed since the beginning of August 1990. The main difference in the gasoline prices in August 1990 and December 1990 was in the substantially higher crude acquisition costs. Average gasoline prices were also higher, but the increase was less than the increase in the cost of crude.

Ottawa - In general, gasoline prices in Ottawa are very stable and relatively high. Ottawa has the highest prices in cities west of Montreal. The disparity in gasoline prices between Ottawa and other Ontario cities is so great that an investigation has been launched to explain the situation. The Department of Consumer and Corporate Affairs will release any findings on unfair trade practices.

Consumption Taxes on Petroleum Products

The GST, QST and their Implications

On January 1, 1991, the federal government imposed the Goods and Services Tax (GST), a 7% tax applied at the retail level. The GST replaced the federal sales tax (FST) which was calculated at 13.5% of an approximate wholesale price. The FST had as its tax base crude costs and refining and marketing costs. The GST, on the other hand, includes the federal excise tax, provincial product taxes and retail markups in addition to the tax base on which the FST was levied.

The initial impact of the federal GST was an average increase in federal taxes of 0.4¢/litre on regular unleaded gasoline in January 1991. By the end of March, however, federal taxes on regular unleaded gasoline decreased 0.4¢/litre.Furnace fuel oil, which had not been subject to a federal tax previously, increased about 3¢/litre in January. As furnace fuel oil prices fell during the quarter, the GST had fallen to about 2.5¢/litre by March 1991.

In addition to higher taxes resulting from the GST on January 1, 1991, four provinces increased their road taxes. Concurrent with the introduction of the GST, the Quebec government implemented an 8% sales tax (QST), which is applied on the GST-included retail price. While the QST tends to drive the gasoline price upwards, it was somewhat offset by a reduction of Quebec's provincial gasoline road tax from 14.4¢/litre to 10¢/litre on January 1, 1991. While Quebec was the only province to reduce its provincial road taxes, the overall effect of the imposition of the GST, the QST and the reduction of road taxes was an average increase in Montreal's gasoline prices of 1.5¢/litre. Approximately 1¢/litre of this increase will go to the Quebec government and the balance to the federal government.

The effect of the imposition of the GST and the QST (Quebec only) is illustrated in the example below. Regular unleaded gasoline prices in Montreal and Winnipeg on December 25, 1990 and January 1, 1991 are used to show the impact of the tax changes.

Table 8.5.
Regular Unleaded Gasoline Prices In Montreal and Winnipeg
December 25, 1990 and January 2, 1991
cents per litre

	Montreal		Winnipeg	
	Dec.25,1990	Jan.2,1991	Dec.25,1990	Jan.2,1991
Retail Price	71.0	72.5	64.9	65.0
Quebec GST(8%)		5.37		
Federal GST(7%)		4.39		4.25
Provincial Tax	14.4	10.0	9.0	9.0
Federal Excise	8.5	8.5	8.5	8.5
Federal Sales	3.83		3.83	
Product Price Change				-0.3
Crude,Refining &,Marketing Costs & Profits & Retail Margin	44.27	44.27	43.57	43.57

Provincial Tax Changes - Five of the provinces, Newfoundland, Nova Scotia, Prince Edward Island, New Brunswick and British Columbia, use an ad valorem system to calculate the taxes they levy on gasoline. While Newfoundland reviews its taxes monthly, the other four review their taxes quarterly.

On January 1, 1991, Nova Scotia increased its ad valorem rate from 22.25% to 24.5%. Provincial taxes in all provinces east of Ontario (except Newfoundland) went up on January 1, 1991. As a result, the weighted average provincial tax increased 0.3 cents per litre to 11.7 cents per litre on January 1, 1991.

At the end of the first quarter of 1991 the average provincial tax was 11.6 cents per litre. A tax hike in Newfoundland in March 1991 (to 13.7 cents per litre from 12.4 cents per litre) was offset by QST-related adjustments made in Quebec. On March 7, 1991, Newfoundland imposed a freeze on its tax rates for the balance of the calendar year.

Regulated Gasoline Markets - Prince Edward Island (PEI) and Nova Scotia were the two provinces with regulated markets in Canada. In PEI, companies must have the approval of its regulatory authority, the Public Utility Commission (PUC), to change prices, be they increases or decreases. The situation in Nova Scotia was different in that its regulatory body, the Board of Commissioners of Public Utilities (PUB) only had to approve price changes. The PUB merely sets a price ceiling and this ceiling may be adjusted downwards to reflect price reductions in the marketplace.

The invasion of Kuwait by Iraq precipitated high petroleum product prices which peaked in January 1991. Subsequently, in response to declining crude oil prices, gasoline prices were lowered across Canada during February and March 1991. However, in the regulated markets, prices did not decline as quickly as in unregulated markets. In mid-February, Charlottetown and Halifax recorded regular unleaded gasoline prices of 73.6 cents per litre and 70 cents per litre, respectively, when the Canada average was 60.6 cents per litre.

The response of regulated markets to changing prices is slow compared to unregulated markets. This is explained by the flow-through policies maintained by the regulatory bodies which delay potential decreases and increases in prices by about two months. The protective umbrella of government regulation of gasoline prices in PEI and Nova Scotia came under heavy criticism during the first quarter of 1991.

On July 11, 1991, the Government of Nova Scotia granted royal assent to amendments to the Gasoline and Fuel Oil Licensing Act. Petroleum product prices were deregulated and barriers to entry into gasoline and fuel oil retailing were reduced. The Government of Nova Scotia hopes these amendments will promote competition, thereby benefiting gasoline and fuel oil consumers.

Canada vs United States - At the end of the fourth quarter of 1990, the average retail price of all grades of motor gasoline in both countries peaked as a result of the Persian Gulf crisis. During first quarter of 1991 a gradual decline in prices was recorded with Canadian and U.S. prices declining 9.8 cents per litre and 8.4 cents per litre, respectively. The price spread between the two countries was highest in January at 25.3 cents per litre, a drastic difference from the spread in March (21 cents per litre). Lower refining and marketing costs and profits in the Canadian downstream industry accounted for the narrowing price spread.

The price differential between Canada and the U.S. is largely due to higher Canadian taxes. Taxes accounted for 58% of the price differential in January and 64.7% in March. The difference in the two months results from turbulent prices and widely changing differentials during the period, not tax changes. Taxes remained approximately the same with the combined Canadian federal and provincial taxes twice as much as the U.S. combined federal and state taxes.

The bulk of the Canada vs. U.S. crude cost differential is a function of longer flow-through periods in Canada attributable to fewer refineries and a relatively limited distribution system. A higher average crude quality in Canada is also a contributing factor.

The larger refining and marketing costs and profits component in Canada results from structural differences between the two markets. Economies of scale in refining, distribution and retailing facilities favour U.S. refiners, marketers and consumers.

Figure 8.5.3
Average Retail Price of Motor Gasoline
(Canada vs United States)
cents per litre

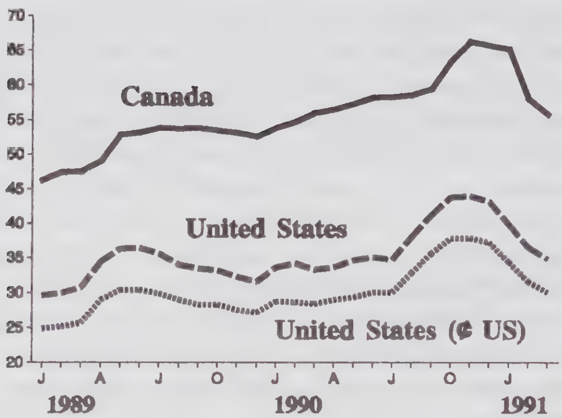
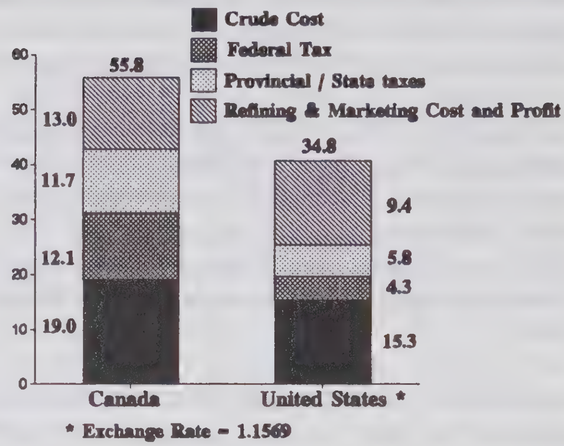


Figure 8.5.4
Breakdown of Average Pump Price
(March 1991) cents per litre



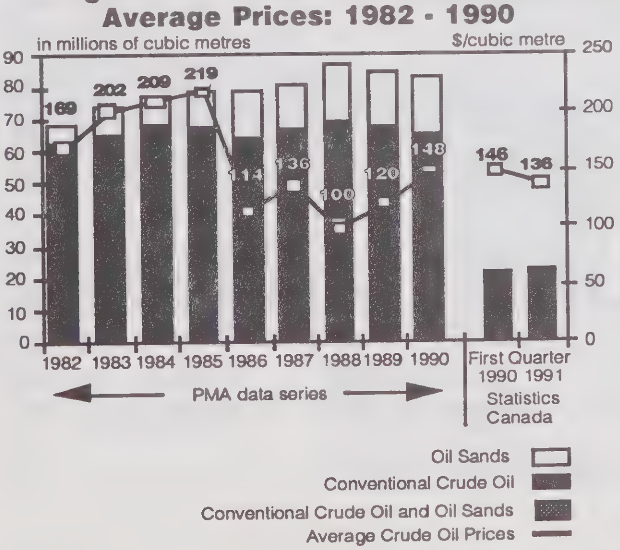
9. Financial Performance of the Canadian Oil and Gas Industry: First Quarter 1991

The following section was prepared by the Petroleum Monitoring Agency (PMA). Further information is available from V. Stanciulescu (613) 995-2100 and F. Laberge 996-8035.

- *Internal cash flow decreased 15% to $1.6 billion in the first quarter of 1991 from $1.9 billion in the corresponding 1990 period.*
- *Net income after unusual items fell 79% to $95 million in the first quarter of 1991.*
- *Gross capital expenditures increased 20% to $2 billion in the first quarter of 1991. The reinvestment rate rose to 125% from 89% in the corresponding 1990 period.*
- *Dividend payments in the first quarter of 1991 increased 58% to $360 million from $225 million.*
- *The petroleum industry's rate of return on capital employed for the one-year period ending March 1991 was 4% vs. 5.1% at the end of 1990. Rate of return on average shareholders' equity was 4.2% for the one-year period ending March 1991, against 6.1% at the end of 1990.*
- *Long-term debt as a percentage of capital employed increased to 40% from 39% at the end of 1990.*

Total sales revenues in the first quarter of 1991 were $11.1 billion, only $35 million higher than the corresponding 1990 period. Lower upstream revenues were offset by higher downstream revenues.

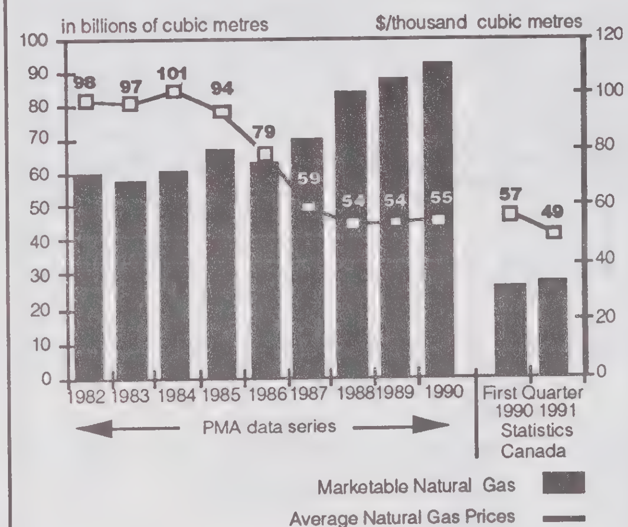
Figure 9.1 Crude Oil Volumes and Average Prices: 1982 - 1990



While international crude oil prices were slightly higher during the quarter, the prices realized by Canadian producers were lower as the Canadian dollar appreciated against the U.S. dollar. International oil prices are generally quoted in U.S. dollars and, as the Canadian dollar strengthens, the Canadian value of oil prices declines (Figure 9.3). Most severely affected were heavy crude oil and natural gas prices - - the latter falling to their lowest level in a decade (Figure 9.2). However, the decline in prices was partly offset by increased production volumes of both crude oil and natural gas.

Refined petroleum products sales were higher as the partial flow through to consumers of increased feedstock costs more than offset the impact of lower volumes.

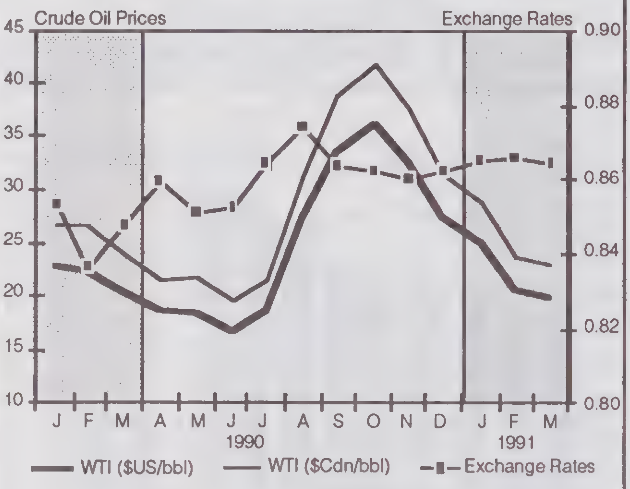
Figure 9.2 Marketable Natural Gas Volumes and Average Prices: 1982 - 1990



Note : The data for figures 9.1 and 9.2 are taken from the PMA's Monitoring Survey results except for the two end bars which are derived from Statistics Canada and EMR Oil and Gas Branch. The two data series are **not** entirely comparable since the PMA data shows prices to the producers, while the other data include transportation and gathering costs and are, therefore, higher than PMA numbers. The Monitoring Survey covers approximately 90% of the industry, compared with 100% for the other data series.

Internal cash flow declined 15% to $1.6 billion in the first quarter of 1991 due to higher expenses registered against unchanged revenues. 'Other expenses', including operating costs, cost of goods sold (feedstock costs) and royalty payments increased $520 million (6%) in the first quarter of 1991 over the corresponding 1990 period, more than offsetting a decrease in interest payments of 13% ($80 million) and a decline in current income taxes of 29% ($135 million) (Table 9.6). One reason for the decline in the industry's profitability was the companies' inability to recover the full amount of higher feedstock costs in their sales to consumers (Figure 9.4).

Figure 9.3 Crude Oil Prices and Exchange Rates



	First Quarter 1990	1991
Avg. WTI ($US/bbl)	21.76	21.82
Avg. Exchange Rate	0.846	0.865
Avg. Cdn. Prices ($Cdn/bbl)	25.73	25.22

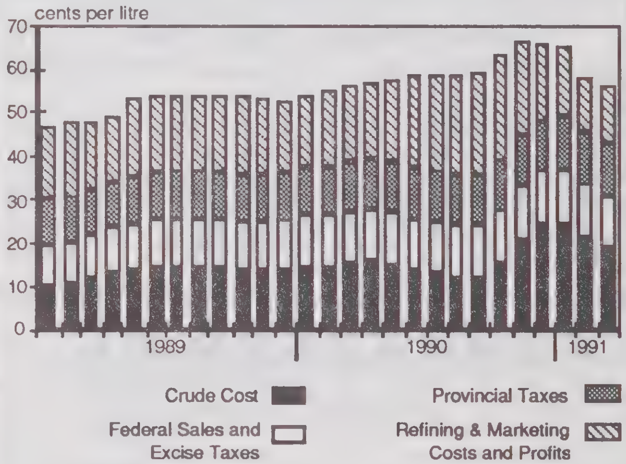
Sources: EMR, Oil and Gas Branch; Bank of Canada

Table 9.1 Overview of Total Industry

	1990	1991	Change	
	---- $ billions ----			(%)
Total Sales Revenue	11.0	11.1	0.1	-
Other Revenues	0.3	0.2	-0.1	-33
Total Expenses	9.8	10.4	0.6	6
All Current Taxes	0.5	0.3	-0.2	-29
Deferred Taxes	-	-1.0	-1.0	-
Net Income before Extraordinary Items	**0.4**	**0.1**	**-0.3**	**-83**
Extraordinary and Other Items	-	-	-	-24
Net Income after Extraordinary Items	**0.5**	**0.1**	**-0.4**	**-79**
Internal Cash Flow	**1.9**	**1.6**	**-0.3**	**-15**

Net income from all Canadian operations of the industry fell 79% to $95 million in the first quarter of 1991. Aside from the factors affecting cash flow, the decline was due to higher depreciation, depletion and amortization, up $50 million (4%) and lower gains on sales of assets and currency translation, down $65 million and $20 million respectively.

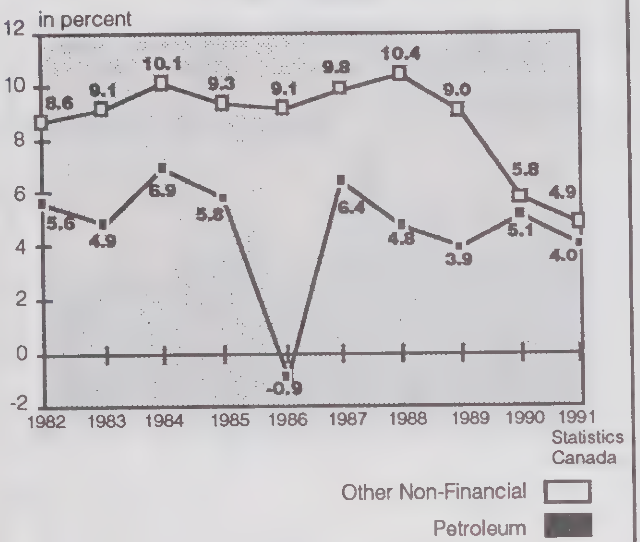
Figure 9.4 Average Retail Price of Motor Gasoline: Monthly, 1989 - 1991



Source: EMR, Oil and Gas Branch

The petroleum industry's **rate of return on capital employed** for the one-year period ending March 1991 was 4% vs. 5.1% at the end of 1990. The other non-financial industries (excluding petroleum) recorded a rate of return on capital employed of 4.9% for the year ending March 1991, vs. 5.8% in 1990 (Figure 9.5 and Note).

Figure 9.5 Rates of Return on Capital Employed



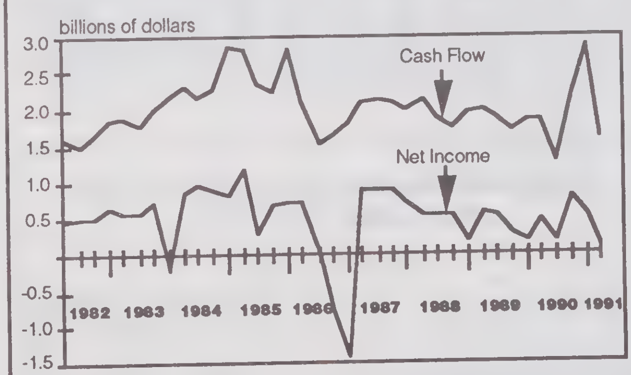
The rate of return on average shareholders' equity for the Canadian petroleum industry was 4.2% for the one-year period ending March 1991, against 6.1% at the end of 1990. By comparison, the rates of return on shareholders' equity for all other non-financial industries during the same periods were 3.5% against 5.1%.

Note : The data presented in this report for other non-financial industries are slightly different from those presented in previous reports due to a number of changes introduced by Statistics Canada to their statistical series beginning with the fourth quarter of 1990.

Canadian-controlled companies' cash flow decreased 10% ($80 million) to $700 million in the first quarter of 1991 from $780 million in the corresponding 1990 period. Lower sales revenue, down $145 million or 4%, and a $30 million increase in 'other expenses', which includes operating and feedstock costs, contributed to reduce profits. Partly offsetting this decline were reduced interest charges and current income taxes of $45 million and $55 million respectively. Net income declined 67% to $45 million in the first quarter of 1991.

Foreign-controlled companies' cash flow fell 18% ($195 million) to $890 million in the first quarter of 1991 compared to $1.1 billion in the corresponding 1990 period. A $180 million (3%) gain in total revenues along with the decline in interest charges (down $35 million) and current income taxes (down $80 million), were more than offset by a $490 million rise in 'other expenses', which includes operating and feedstock costs, and royalty payments. Net income for this group fell $280 million (84%). In addition to the factors mentioned above, net income was negatively affected by higher E&D expenses, up $95 million, and higher depletion, depreciation and amortization charges, up $45 million.

Figure 9.6. Net Income and Cash Flow 1982 - 1991: Quarterly Data



Dividend payments by the petroleum industry increased 58% to $360 million in the first quarter of 1991 from $230 million in the corresponding 1990 period. Dividends paid by Canadian-controlled companies increased 30% to $130 million, while dividend payments by foreign-controlled companies rose 81% to $230 million. The unusually high payout rate for both groups was partly the result of netting out of losses reported by a large number of companies against gains, thus considerably reducing the denominator of the payout ratio.

Table 9.2 Dividend Payments

	First Quarter		Per Cent of Net Income(a)	
	1990	1991	1990	1991
	- -$ millions - -		(%)	
Canadian-Controlled	101	131	76	297
Foreign-Controlled	126	229	38	440
Total Industry	227	360	49	375

(a) Percentages are derived by dividing dividend payments by net income.

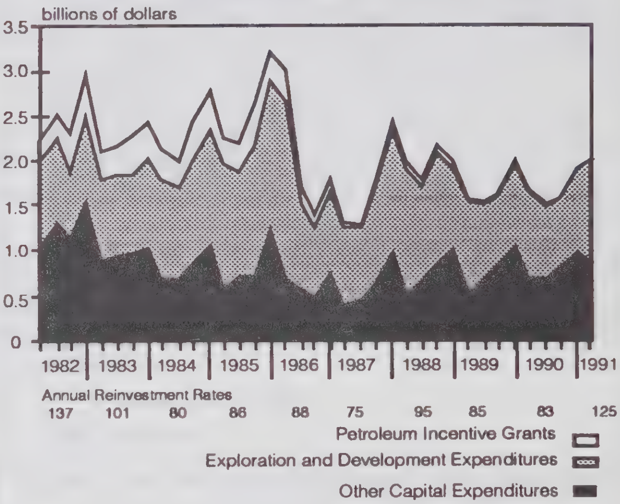
Overall gross capital expenditures for the petroleum industry increased 20% ($330 million) to $2 billion in the first quarter of 1991. Net of grants and incentives, capital expenditures rose 21%. The substantial rise is the result of increased capital investment in major projects, such as the Caroline gas field development and the Bi-Provincial heavy oil upgrader.

Table 9.3 Capital Expenditures and Reinvestment Rates

First Quarter	1990	1991	Change	
	--- $	billions ---		(%)
Gross Capital Expenditures	1.7	2.0	0.3	20
Less: Incentive Grants	0.1	-	-	-88
Net Capital Expenditures	1.6	2.0	0.4	21
Reinvestment Rate: Net Capital Expenditures as a Per Cent of Cash Flow	89%	125%		

Exploration and development spending rose 13% to $1.1 billion in the first quarter of 1991, while other capital expenditures increased 30% to $855 million. A 20% increase in gross capital expenditures for both Canadian and foreign-controlled companies resulted in outlays of $960 million and $1 billion respectively (Table 9.5).

Figure 9.7 Capital Expenditures and Reinvestment Rates: 1982 - 1991



The total reinvestment rate increased to 125% in the first quarter of 1991 from 89% in the corresponding 1990 period (Table 9.4). The reinvestment rate for Integrateds and Refiners increased to 104% from 74%, while that of the Oil and Gas Producers group rose to 140% from 100%.

Table 9.4 Total Capital Expenditures (Net Of Incentive Grants) as a Per Cent of Internal Cash Flow
First Quarter

	1990	1991
	-------(%)------	
Integrateds and Refiners	74	104
Canadian-Controlled	139	242
Foreign-Controlled	60	79
Senior Oil and Gas Producers	88	137
Canadian-Controlled	75	99
Foreign-Controlled	105	201
Junior Oil and Gas Producers	122	145
Canadian-Controlled	127	149
Foreign-Controlled	113	136
Oil and Gas Producers	100	140
Canadian-Controlled	95	119
Foreign-Controlled	107	178
Total Industry	**89**	**125**
Canadian-Controlled	103	137
Foreign-Controlled	79	116

Debt to Equity Analysis:(1)

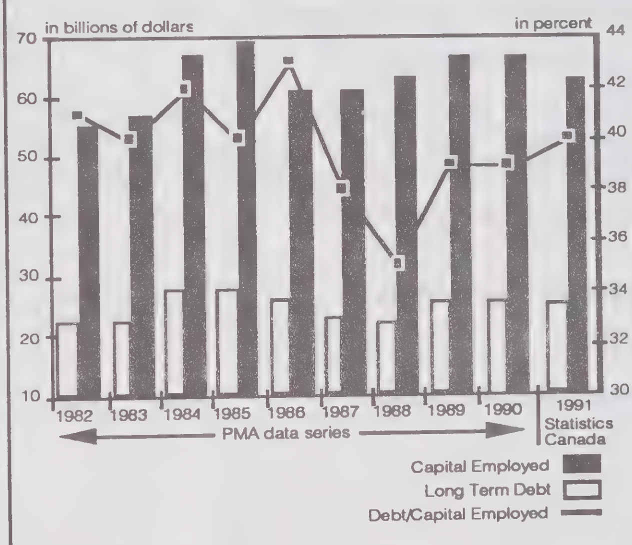
In the first quarter of 1991 the industry's long-term debt increased slightly (1%) to $25.2 billion from $25 billion at the end of 1990. Canadian-controlled companies' debt declined by less than 1% as long-term debt became due and thus included with short-term debt. In addition, changes took place within the debt categories whereby, long-term debt was transferred to the 'other long-term liability' category following financial or operational reorganizations. The foreign-controlled group increased their debt by 2% ($340 million) mainly to fund higher spending on major capital projects (Table 9.7).

During the same period total shareholders' equity declined by 1% ($365 million) to $37.3 billion. The decline was entirely attributable to the Canadian-controlled group of companies, and was the result of restructuring activity by a number of companies; the decline was accompanied by a slight change in the equity structure, as contributed surplus was converted to common share capital.

As a result of the above changes in debt and equity, the ratio of debt to capital employed (defined as long-term debt, other long-term liabilities and total equity) increased to 40% from 39% at the end of 1990 (Figure 9.8).

(1) Debt includes long-term debt and other long-term liabilities.

Figure 9.8 Long-Term Debt to Capital Employed



Note : This report was prepared on the basis of the quarterly data obtained from individual companies by the PMA via Statistics Canada. In contrast to the bi-annual PMA survey presentation, the report covers the combined results of upstream, downstream and other Canadian operations but excludes the results of Canadian companies' foreign activities. Nonetheless, the information contained in this analysis gives a reliable overview of the industry's financial performance for the first quarter of 1991.

July 1991

Table 9.5

Capital Expenditures of Petroleum Industry
First Quarter

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1990	1991	Change %	1990	1991	Change %	1990	1991	Change %
	$ millions			$ millions			$ millions		
Exploration and Development									
E&D Expensed									
Land & Lease Acquisition and Retention	28	23	-18	2	4	54	25	19	-25
Drilling Expenditures	92	119	29	51	54	6	41	65	59
Geological and Geophysical	106	92	-13	10	8	-20	96	84	-13
Total E&D Expensed	226	234	4	63	66	5	162	168	4
E&D Capitalized									
Land & Lease Acquisition and Retention	162	131	-19	84	64	-24	78	67	-14
Drilling Expenditures	536	667	24	312	354	13	223	313	40
Geological and Geophysical	81	106	31	57	70	23	24	37	54
Total E&D Capitalized	779	904	16	453	488	8	325	417	28
Total Exploration and Development	**1005**	**1138**	**13**	**516**	**554**	**7**	**487**	**585**	**20**
Other Capitalized Expenditures									
Mining	19	22	16	11	12	13	9	9	9
New Const., Build., Mach., and Equip.	568	761	34	258	368	43	310	393	27
Used Build., Mach., Equip., & Land	30	21	-30	6	7	17	25	14	-44
Other Capital Expenditures	39	52	33	13	22	69	26	30	15
Total Other Capital Expenditures	656	856	30	288	409	42	370	446	21
Total Capital Expenditures	**1661**	**1994**	**20**	**804**	**963**	**20**	**857**	**1031**	**20**
Capital Grants	9	1	-88	4	1	-75	5	-	-90
Net Capital Expenditures	**1652**	**1993**	**21**	**800**	**962**	**20**	**852**	**1032**	**21**

PMA, July 1991

Table 9.6

Income Statement
First Quarter

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1990	1991	Change %	1990	1991	Change %	1990	1991	Change %
	$ millions			$ millions			$ millions		
Sales Revenues	11049	11085	-	3899	3754	-4	7150	7331	3
Other Revenues									
Interest from Canadian Sources	101	85	-16	39	36	-8	61	49	-21
Dividends from Canadian Corporations	20	32	55	17	18	9	4	13	-
Foreign Dividends and Interest Revenues	3	5	47	-	1	48	3	4	32
Gains on Sale of Assets	127	61	-52	14	6	-59	114	56	-51
Total Revenues	**11300**	**11267**	**-**	**3969**	**3815**	**-4**	**7331**	**7452**	**2**
Expenses									
E & D Expensed	232	240	4	64	66	3	168	174	4
D, D & A Charges	1336	1385	4	562	564	-	774	821	6
Other Expenses	8249	8767	6	2815	2845	1	5434	5922	9
Interest Expenses	607	526	-13	278	232	-17	329	294	-11
Total Operating Expenses	**10423**	**10918**	**5**	**3719**	**3706**	**-**	**6704**	**7212**	**8**
Other Transactions									
Gains on Translation of Currency	21	1	-95	-6	-18	-	26	19	-30
Write-offs and Valuation Adjustments	-22	-30	-	-2	-2	-	-20	-28	-
Income before Income Taxes	**875**	**320**	**-64**	**242**	**89**	**-63**	**634**	**231**	**-64**
Income Taxes									
Current	457	324	-29	85	32	-63	373	292	-22
Deferred (tax allocation method)	-9	-76	-	66	47	-30	-75	-123	-
Net Income after Income taxes	**427**	**73**	**-83**	**91**	**11**	**-88**	**336**	**62**	**-82**
Other Income									
Equity Income	36	22	-35	42	33	-21	-6	-10	-
Extraordinary Items	-	-	-	-	-	-	-	-	-
Net Income after Extraordinary Items	**463**	**96**	**-79**	**133**	**44**	**-67**	**330**	**52**	**-84**
Cash Flow	**1859**	**1590**	**-15**	**777**	**702**	**-10**	**1082**	**888**	**-18**

	Integrateds and Refiners			Oil and Gas Producers		
	1990	1991	Change %	1990	1991	Change %
	$ millions			$ millions		
Sales Revenues	7129	6978	-2	3919	4106	5
Other Revenues						
Interest from Canadian Sources	48	40	-18	52	45	-14
Dividends from Canadian Corporations	3	6	-	18	26	45
Foreign Dividends and Interest Revenues	-	-	-	3	5	45
Gains on Sale of Assets	121	62	-49	6	-1	-
Total Revenues	**7301**	**7086**	**-3**	**3999**	**4181**	**5**
Expenses						
E & D Expensed	59	78	34	173	162	-7
D, D & A Charges	551	572	4	785	814	4
Other Expenses	5948	6120	3	2301	2647	15
Interest Expenses	279	231	-17	328	295	-10
Total Operating Expenses	**6837**	**7000**	**2**	**3587**	**3918**	**9**
Other Transactions						
Gains on Translation of Currency	-5	6	-	26	-5	-
Write-offs and Valuation Adjustments	-13	4	-	-9	-34	-
Income before Income Taxes	**446**	**96**	**-79**	**429**	**224**	**-48**
Income Taxes						
Current	166	20	-88	292	303	4
Deferred (tax allocation method)	46	35	-24	-55	-111	-
Net Income after Income taxes	**234**	**41**	**-83**	**192**	**32**	**-84**
Other Income						
Equity Income	12	17	37	24	7	-67
Extraordinary Items	-	-	-	-	-	-
Net Income after Extraordinary Items	**247**	**58**	**-77**	**216**	**39**	**-82**
Cash Flow	**788**	**653**	**-17**	**1072**	**937**	**-13**

Table 9.7

Balance Sheet

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1990	1991	Change %	1990	1991	Change %	1990	1991	Change %
	$ millions			$ millions			$ millions		
Cash, Investments and Marketable Securities	810	660	-18	328	325	-1	481	335	-30
Accounts Receivable:									
Trade (include affiliates)	6571	5563	-15	2270	1990	-12	4302	3573	-17
All Other	467	553	18	308	262	-15	159	291	83
Total	7038	6116	-13	2578	2252	-13	4460	3864	-13
Inventories	5481	4597	-16	1607	1378	-14	3874	3219	-17
Other Current Assets	818	1710	109	320	311	-3	499	1399	180
Total Current Assets	**14147**	**13083**	**-8**	**4833**	**4266**	**-12**	**9314**	**8817**	**-5**
Net Fixed and Depletable Assets	62372	62323	-	25730	25749	-	36641	36574	-
Other Long-term Assets	8531	8255	-3	4862	4810	-1	3671	3445	-6
Total Assets	**85050**	**83661**	**-2**	**35425**	**34825**	**-2**	**49626**	**48836**	**-2**
Accounts payable:									
Trade (include affiliates)	5540	4599	-17	2358	2004	-15	3182	2596	-18
All Other	1605	1954	22	304	516	70	1302	1437	10
Total	7145	6553	-8	2662	2520	-5	4483	4033	-10
Other Current Liabilities	4356	3771	-13	1841	1822	-1	2516	1949	-23
Total Current Liabilities	**11501**	**10324**	**-10**	**4503**	**4342**	**-4**	**6999**	**5982**	**-15**
Long-term Debt	21034	21437	2	8493	7888	-7	12541	13547	8
Accumulated Deferred Income Taxes	10939	10842	-1	4276	4278	-	6663	6564	-1
Other Long-term Liabilities	3922	3771	-4	1575	2093	33	2346	1681	-28
Sareholders' Equity									
Common	13981	14247	2	7421	7664	3	6559	6582	-
Preferred	3613	3558	-2	2206	2161	-2	1408	1397	-1
Retained earnings	14975	14768	-1	3546	3434	-3	11429	11334	-1
Contributed surplus	5085	4714	-7	3405	2965	-13	1681	1749	4
Total Liabilities, Deferred Taxes and Equity	**85050**	**83661**	**-2**	**35425**	**34825**	**-2**	**49626**	**48836**	**-2**
Working Capital	**2646**	**2759**	**4**	**330**	**-76**	**-**	**2315**	**2835**	**22**

	Integrateds and Refiners			Oil and Gas Producers		
	1990	1991	Change %	1990	1991	Change %
	$ millions			$ millions		
Cash, Investments and Marketable Securities	149	135	-9	660	524	-21
Accounts Receivable:						
Trade (include affiliates)	4007	3473	-13	2564	2090	-18
All Other	151	286	89	316	266	-16
Total	4158	3759	-10	2880	2356	-18
Inventories	4837	4054	-16	644	543	-16
Other Current Assets	240	732	-	580	980	69
Total Current Assets	**9384**	**8680**	**-8**	**4764**	**4403**	**-8**
Net Fixed and Depletable Assets	27901	27809	-	34471	34514	-
Other Long-term Assets	2468	2498	1	6063	5757	-5
Total Assets	**39753**	**38987**	**-2**	**45297**	**44674**	**-1**
Accounts payable:						
Trade (include affiliates)	3244	2517	-22	2296	2083	-9
All Other	1022	1121	10	583	833	43
Total	4266	3637	-15	2879	2916	1
Other Current Liabilities	2784	2313	17	1572	1458	-7
Total Current Liabilities	**7050**	**5950**	**-16**	**4451**	**4374**	**-2**
Long-term Debt	7901	8430	1	13134	13006	-1
Accumulated Deferred Income Taxes	5504	5486	-	5435	5356	-1
Other Long-term Liabilities	1523	1447	5	2398	2325	-3
Sareholders' Equity						
Common	5048	5259	4	8932	8987	1
Preferred	15	15	-	3598	3544	-2
Retained earnings	9657	9490	-2	5318	5278	-1
Contributed surplus	3055	2910	-5	2031	1804	-11
Total Liabilities, Deferred Taxes and Equity	**39753**	**38987**	**-2**	**45297**	**44674**	**-1**
Working Capital	**2334**	**2730**	**17**	**313**	**29**	**-91**

PMA, July 1991

Appendix I
Production of Canadian Crude Oil and Equivalent

	1989 Year	1990 1Q	1990 2Q	1990 3Q	1990 4Q	1990 Year	1991 1Q
	--(000 m^3/d)						
A. Light and Equivalent							
Alberta	124.3	120.9	113.0	116.7	116.6	116.8	117.1
B.C.	5.2	5.6	5.0	5.1	5.4	5.3	5.7
Saskatchewan	10.6	10.9	10.8	12.4	12.4	11.7	10.6
Manitoba	1.9	2.0	2.0	2.0	2.0	2.0	2.0
Ontario	0.7	0.7	0.7	0.6	0.6	0.6	0.6
Other	4.9	5.1	5.0	4.9	5.2	5.0	5.2
Total	**147.6**	**145.2**	**136.5**	**141.7**	**142.2**	**141.4**	**141.2**
Synthetic							
Suncor	9.1	9.2	5.0	8.3	10.3	8.2	9.4
Syncrude	23.6	15.9	28.9	26.6	27.2	24.6	25.2
Total	**32.7**	**25.1**	**33.9**	**34.9**	**37.5**	**32.8**	**34.6**
Pentanes Plus*	**7.8**	**5.8**	**6.9**	**6.4**	**6.7**	**6.4**	**6.3**
Total Light	**188.1**	**176.1**	**177.3**	**183.0**	**186.4**	**180.6**	**182.1**
B. Heavy Crude Alberta							
Conventional	25.2	28.0	27.8	28.3	29.0	23.3	27.2
Bitumen	20.5	21.4	19.4	22 3	22.9	21.5	21.6
Diluent	8.2	10.0	7.8	8.7	10.0	9.1	9.7
Total	**53.9**	**59.4**	**55.0**	**59.3**	**61.9**	**58.9**	**58.5**
Saskatchewan							
Conventional	21.1	21.5	21.7	21.1	21.5	21.5	23.1
Diluent	2.6	3.0	2.8	2.5	2.8	2.8	3.5
Total	**23.7**	**24.5**	**24.5**	**23.6**	**24.3**	**24.3**	**26.6**
Total Heavy	**77.6**	**83.9**	**79.5**	**82.9**	**86.2**	**83.2**	**85.1**
C. Production	**265.6**	**260.0**	**256.8**	**265.9**	**272.6**	**263.8**	**267.2**
D. Shut-In							
Light	5.3	4.4	8.5	5.0	3.7	5.4	1.5
Heavy	2.9	0.6	0	-0.4	-3.7	-0.9	0
Total	**8.2**	**5.0**	**8.5**	**4.6**	**0**	**4.5**	**1.5**
E. Total Capacity	**273.9**	**265.0**	**265.3**	**270.5**	**272.6**	**268.3**	**268.7**

** excludes diluent*

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Appendix II
Supply and Disposition of Canadian Crude Oil and Equivalent

	1989 Year	1990 1Q	1990 2Q	1990 3Q	1990 4Q	1990 Year	1991 1Q
	(000 m³/d)						
A. Light and Equivalent							
Supply							
Production	188.1	176.1	177.3	183.0	186.4	180.7	182.2
Newgrade	0.1	0.5	1.1	1.4	2.4	1.4	1.7
Draw/(Build)	2.8	5.1	-0.3	6.7	3.5	3.8	6.5
Net Supply	191.0	181.7	178.1	191.1	192.3	185.9	190.4
Domestic Demand							
Atlantic	0	0	0	0	0	0	0
Quebec	9.3	7.1	11.4	9.7	4.1	8.1	4.9
Ontario	64.6	67.6	55.4	65.8	70.0	64.7	56.6
Prairies	52.7	53.7	46.0	49.4	51.6	50.2	45.1
B.C.	17.3	17.7	17.4	18.8	18.5	18.1	18.1
Total	**143.9**	**146.0**	**130.2**	**143.7**	**144.3**	**141.1**	**124.7**
Exports	47.2	35.6	48.0	47.4	48.0	44.8	65.6
Total Demand	**191.1**	**181.6**	**178.2**	**191.1**	**192.3**	**185.9**	**190.3**
B. Heavy Crude (Blended)							
Supply							
Production	77.7	83.9	79.4	82.9	86.2	83.2	85.0
Recycled Diluent	1.2	0.5	1.3	1.5	0.8	1.0	0.7
Draw/(Build)	-1.1	-1.8	0.2	1.8	-2.7	-0.7	-0.9
Net Supply	77.8	82.6	80.9	86.2	84.3	83.5	84.8
Domestic Demand							
Atlantic	0.1	0	0.4	0.9	0.2	0.4	0
Quebec	4.3	5.1	4.9	4.1	1.2	3.8	0
Ontario	9.7	8.9	7.0	8.4	10.2	8.7	9.1
Prairies	7.3	7.3	11.1	14.6	10.4	10.8	9.1
B.C.	0.6	0.2	0.3	0.4	0.8	0.4	0.5
Total	**21.9**	**21.6**	**23.6**	**28.4**	**22.8**	**24.1**	**18.8**
Exports	**55.7**	**61.1**	**57.3**	**57.8**	**61.4**	**59.4**	**66.1**
Total Demand	**77.6**	**82.7**	**80.9**	**86.2**	**84.2**	**83.5**	**84.9**

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Appendix III
Crude Oil Exports by Destination

U.S. PAD* Districts		1989 Year	1990 1Q	1990 2Q	1990 3Q	1990 4Q	1990 Year	1991 1Q
		(000 m³/d)						
PADD I	Light	7.4	6.3	7.8	7.8	7.0	7.3	6.5
	Heavy	1.3	1.8	1.1	1.2	1.2	1.3	1.7
	Total	**8.7**	**8.1**	**8.9**	**9.0**	**8.2**	**8.6**	**8.2**
PADD II	Light	27.3	19.0	29.2	28.4	31.2	27.0	47.2
	Heavy	48.3	50.5	50.3	52.5	54.2	51.9	55.5
	Total	**75.6**	**69.5**	**79.5**	**80.9**	**85.4**	**78.9**	**102.7**
PADD III	Light	0	0	0	0	0	0	0
	Heavy	1.5	3.3	1.4	0	0.6	1.3	3.1
	Total	**1.5**	**3.3**	**1.4**	**0**	**0.6**	**1.3**	**3.1**
PADD IV	Light	9.1	9.0	9.5	10.5	8.8	9.4	9.4
	Heavy	2.7	2.3	2.9	3.4	3.4	3.0	2.9
	Total	**11.8**	**11.3**	**12.4**	**13.9**	**12.2**	**12.4**	**12.3**
PADD V	Light	2.8	0.7	1.3	0.8	0.4	0.7	1.3
	Heavy	0.6	0.8	0.8	0.8	1.1	0.9	0.4
	Total	**3.4**	**1.5**	**2.1**	**1.6**	**1 5**	**1.6**	**1.7**
U.S.	**Light**	**46.6**	**35.0**	**47.8**	**47.5**	**47.4**	**44.4**	**64.4**
	Heavy	**54.4**	**58.7**	**56.5**	**57.9**	**60.5**	**58.4**	**63.6**
	Total	**101.0**	**93.7**	**104.3**	**105.4**	**107.9**	**102.8**	**128.0**
Offshore	Light	0.4	0.4	0	0	0	0.1	0.8
	Heavy	1.4	2.5	0.8	0	1 6	1 2	2.3
	Total	**1.8**	**2.9**	**0.8**	**0.0**	**1.6**	**1.3**	**3.1**
Total	**Light**	47.0	35.4	47.8	47.5	47.4	44.5	65.2
	Heavy	55.8	61.2	57.3	57.9	62.1	59.6	65.9
	Total	**102.8**	**96.6**	**105.1**	**105.4**	**109.5**	**104.1**	**131.1**

** U.S. Petroleum Administration for Defense (PAD) Districts*

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Appendix IV
Pipeline Deliveries

	1989 Year	1990 1Q	2Q	3Q	4Q	Year	1991 1Q
	(000 m³/d)						
A. Trans Mountain Pipe Line (TMPL)							
Domestic Deliveries							
Light Crude	13.9	13.5	14.4	15.4	14.9	14.6	14.5
Heavy Crude	0.6	0.2	0.3	0.3	0.3	0.3	0.4
Semi Refined Poducts	5.4	5.1	5.0	5.6	5.3	5.3	5.5
Refined Products	2.7	2.7	2.6	2.6	2.7	2.6	2.4
Total	**22.7**	**21.5**	**22.3**	**23.9**	**23.3**	**22.8**	**22.8**
Foreign Deliveries							
Tankers	2.7	4.4	1.6	1.1	4.7	3.0	5.7
Puget Sound Area	2.7	0.7	1.3	0.5	0.7	0.8	1.1
Total	**5.4**	**5.1**	**2.9**	**1.6**	**5.4**	**3.8**	**6.8**
Total TMPL	**28.1**	**26.6**	**25.2**	**25.5**	**28.7**	**26.6**	**29.6**
B. Interprovincial Pipe Line (IPL)							
Domestic Deliveries							
Light Crude	93.9	93.3	78.7	88.6	86.8	87.0	75.4
Heavy Crude	17.9	19.7	17.5	17.9	14.4	17.4	12.3
Other(1)	26.4	27.6	28.0	23.1	28.3	26.8	27.4
Total	**139.9**	**140.6**	**124.2**	**129.6**	**129.5**	**131.2**	**115.1**
Foreign Deliveries(2)							
Light Crude	42.0	33.4	46.3	42.3	44.3	41.7	61.0
Heavy Crude	49.6	52.3	51.4	53.9	55.1	53.2	57.6
Total	**91.6**	**85.7**	**97.7**	**96.2**	**99.4**	**94.9**	**118.6**
Total IPL	**231.5**	**226.3**	**221.9**	**225.8**	**228.9**	**226.1**	**233.7**
C. Pipeline to Montreal							
IPL Deliveries							
To Montreal	14.5	12.5	16.3	14.3	5.8	12.2	4.8
For Export/Transfer	2.0	4.5	0.4	0.6	0	1.2	0
Total IPL	**16.4**	**17.0**	**16.7**	**14.9**	**5.1**	**13.4**	**4.8**
Portland-Montreal							
Montreal Imports(3)	13.2	16.8	9.2	17.9	24.2	17.0	24.0
Total Mtl Receipts	**27.6**	**29.3**	**25.5**	**32.2**	**30.0**	**29.2**	**28.8**

Note (1): includes petroleum products and NGL's.
(2): includes US domestic crudes delivered to the U.S.
(3): includes cargo imported directly into Montreal.

Appendix V
Canadian Refinery Receipts

	1989 Year	1990 1Q	2Q	3Q	4Q	Year	1991 1Q
	-----	-----	-----	(000 m³/d)	-----	-----	-----
A. Domestic Receipts							
Light & Equivalent							
Atlantic	0	0	0	0	0	0	0
Quebec	9.3	7 1	11.4	9.7	4.1	8.1	4.9
Ontario	64.6	67.5	55.3	65.8	70.0	64.7	56.6
Prairies	52.7	53.7	46.0	49.5	51.6	50.2	45.1
B.C.	17.3	17.6	17.4	18.9	18.5	18.1	18.1
Total	**143.8**	**145.9**	**130.1**	**143.9**	**144.2**	**141.1**	**124.7**
Heavy							
Atlantic	0	0	0.4	0.9	0.2	0.4	0
Quebec	4.3	5.2	4.9	4.2	1.2	3.9	0
Ontario	9.7	8.8	7.0	8.4	10.2	8.6	9.1
Prairies	7.3	7.4	11.1	14.5	10.4	10.9	9.0
B.C.	0.6	0.2	0.3	0.4	0.8	0.4	0.6
Total	**21.9**	**21.6**	**23.7**	**28.4**	**22.8**	**24.2**	**18.7**
Other Receipts*							
Atlantic	0.8	0.8	0.5	0.1	0	0.3	0
Quebec	1.2	1.4	1.1	0.4	0.5	0.9	0
Ontario	4.3	3.3	3.9	2.9	3.7	3.4	3.1
Prairies	3.4	3.4	2.6	2.9	3.7	3.2	3.6
B.C.	5.8	5.3	5.0	5.9	5.4	5.4	5.5
Total	**15.5**	**14.2**	**13.1**	**12.2**	**13.3**	**13.2**	**12.2**
Total Domestic Receipts							
Atlantic	0.8	0.8	0.9	1.0	0.2	0.7	0
Quebec	14.8	13.7	17.4	14.3	5.8	12.9	4.9
Ontario	78.6	79.6	66.2	77.1	83.9	76.7	68.8
Prairies	63.4	64.5	59.7	66.9	65.7	64.3	57.7
B.C.	23.7	23.1	22.7	25.2	24.7	23.9	24.2
Total	**181.1**	**181.7**	**166.9**	**184.5**	**180.3**	**178.5**	**155.6**
B. Crude Oil Imports							
Atlantic	46.3	50.2	47.3	48.3	47.7	48.4	50.7
Quebec	26.5	35.2	25.0	36.9	43.1	35.1	39.6
Ontario	4.3	5.1	2.6	2.1	1.5	2.8	0.6
Prairies	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	0	0
Total	**77.0**	**90.5**	**74.9**	**87.3**	**92.3**	**86.3**	**90.9**
C. Total Receipts*							
Atlantic	47.1	51.5	48.2	49.4	47.9	49.1	50.7
Quebec	41.3	48.9	42.4	51.2	48.9	48.0	44.5
Ontario	82.9	84.7	68.8	79.2	85.4	79.5	69.4
Prairies	63.4	64.5	59.7	66.9	65.7	64.3	57.7
B.C.	23.7	23.1	22.7	25.2	24.7	23.9	24.2
Total	**258.4**	**272.2**	**241.8**	**271.8**	**272.6**	**264.8**	**246.5**

* *Partially processed oil, gas plant butanes etc.*

Appendix VI
International and Domestic Crude Oil Prices
(US$/bbl)

A.

At Source		Canadian Par	WTI NYMEX	Brent
1990	1Q	21.17	21.71	19.81
	2Q	17.33	17.97	16.27
	3Q	25.34	26.28	26.44
	4Q	30.94	32.08	32.66
	Ave	23.73	24.49	23.87
1991	Jan	23.74	24.70	23.63
	Feb	19.48	20.56	19.29
	Mar	18.83	19.88	19.64
	1Q	20.72	21.81	20.95

B.

At Chicago		Canadian Par	WTI NYMEX	Brent
1990	1Q	22.34	22.31	21.63
	2Q	18.61	18.56	18.07
	3Q	26.66	26.88	28.27
	4Q	32.25	32.67	34.54
	Ave	25.00	25.09	25.70
1991	Jan	25.03	25.30	25.91
	Feb	20.76	21.15	21.82
	Mar	20.11	20.48	21.66
	1Q	22.01	22.41	23.22

C.

At Montreal		Canadian Par	WTI NYMEX	Brent
1990	1Q	22.50		21.99
	2Q	18.85		17.86
	3Q	26.90		27.88
	4Q	32.48		34.41
	Ave	25.21		25.61
1991	Jan	25.31		25.62
	Feb	21.05		21.34
	Mar	20.39		21.40
	1Q	22.29		22.88

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Appendix VII
Average Regular Unleaded Gasoline Prices
(Self-Serve)
1990-1991

	----------1990----------				1991
	March 27	June 26	Sept 25	Dec 25	March 26
	----------cents per litre----------				
St John's (NFLD)	58.3	59.6	64.4	72.6	62.0
Charlottetown	56.2	57.7	58.5	68.4	65.6
Halifax*	53.8	57.5	56.3	70.6	61.7
Saint John (N.B.)*	55.2	55.9	60.1	67.3	57.7
Montreal	60.8	61.9	64.0	71.0	63.0
Toronto	48.5	53.9	59.3	58.8	54.8
Winnipeg	53.9	49.9	56.9	64.9	49.0
Regina	54.9	54.9	58.9	62.9	49.9
Calgary	51.9	53.3	55.7	60.0	42.0
Vancouver	59.9	59.9	64.9	66.6	55.4
Average	**54.8**	**56.8**	**60.8**	**64.6**	**55.6**
Consumption taxes inlcude:					
Federal	12.1	12.1	12.2	12.3	12.0
Provincial	11.3	11.4	11.3	11.4	11.6

* *Full-Serve*

Appendix VIII
Consumption Taxes on Petroleum Products
(March 1991)

	Ad valorem		Gasoline			Diesel
	Mogas	Diesel	Reg L	Mid UL	Prem UL	
	---------- % ----------		------------------ (cents per litre) --------------			
Federal Taxes						
Estimated GST (7%)			3.4*	3.7*	3.9*	3.7*
Excise			8.50	8.5	8.5	4.0
Provincial Taxes						
Newfoundland [a]	23	27	13.7*	13.7*	13.7*	15.6*
Prince Edward Island	23	26	13.6*	13.6*	13.6*	13.8*
Nova Scotia	24.5*	31.5	13.7*	13.7*	13.7*	16.2*
New Brunswick	24.5	31.5	11.5*	11.5*	11.5*	11.6*
Quebec [b]			14.9*	15.1*	15.3*	13.3*
Ontario			11.3	11.3	11.3	10.9
Manitoba			9.0	9.0	9.0	9.9
Saskatchewan			10.0	10.0	10.0	10.0
Alberta			7.0	7.0	7.0	7.0
British Columbia [c]	22.5	(d)	11.0*	11.0*	11.0*	11.44*
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	(e)	11.2*	11.2*	11.2*	9.5*

(a) The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay, Labrador.

(b) Reduced by varying amounts in certain remote areas and within 20 kilometres of the provincial and U.S. borders.

(c) Additional transit tax of 3.0 cents per litre in Vancouver.

(d) The tax on diesel 0.44 cents per litre higher than the unleaded tax.

(e) 85% of gasoline tax.

** changed since last quarter*

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional area	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude Oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydro carbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Shut-in capacity	The unused production capability of currently producing oil and gas wells plus the total production capability of all shut-in oil and gas wells, regardless of whether or not they are connected to surface gathering and production facilities.
Synthetic crude oil	Crude oil production treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

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THE ENERGY OF OUR RESOURCES

THE POWER OF OUR IDEAS

THE CANADIAN OIL MARKET

Vol. VII, No. 2, Summer 1991

Canadian Oil Markets and Emergency Planning Division
Energy Sector
Energy, Mines and Resources Canada

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The Canadian Oil Market

1 Refined Product Demand

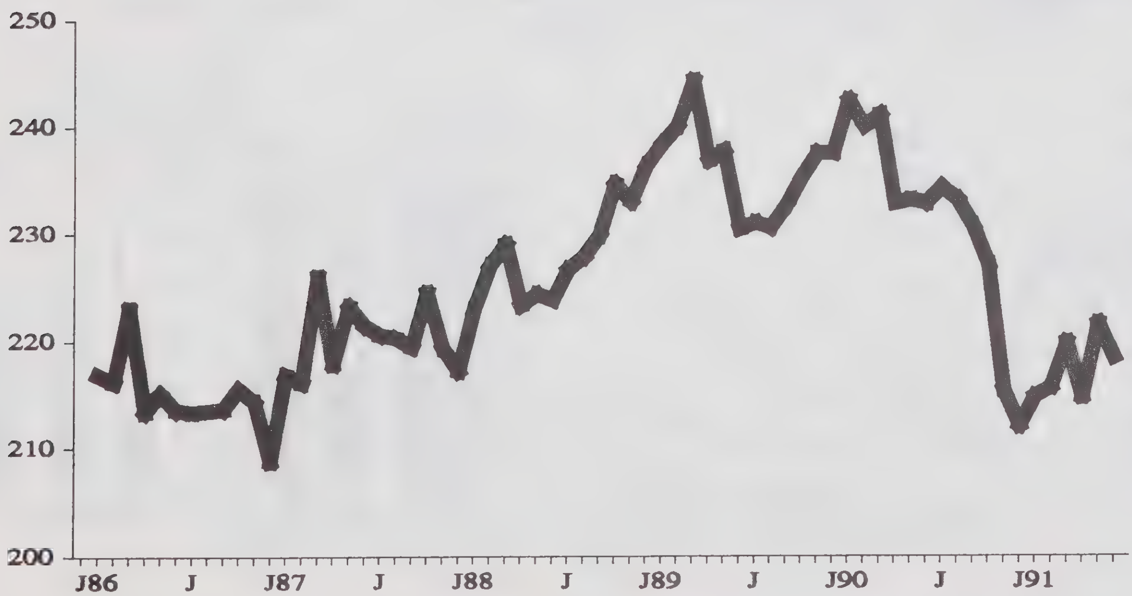
. *The slump in domestic product sales abated in the second quarter, with demand down by just 5% year-over-year. Heavy fuel oil and 'other' products accounted for most of the decline.*

After falling by about 10% year-over-year in the previous two quarters, the decline in demand for refined products moderated somewhat in the second quarter of 1991, with sales down by just 5% or 11 000 m^3/d, to 215 000 m^3/d. Both a modest upturn in the economy and a general reduction in prices following their sharp escalation during the Persian Gulf conflict appear to have been the principal mitigating factors. Although all regions saw lower sales, over 90% of the decline occurred in eastern Canada, particularly in the Atlantic and Quebec regions where sales were down by almost 10%.

Sales of motor gasoline and diesel fuel both declined by about 1 000 m^3/d, to 93 000 m^3/d and 44 000 m^3/d, respectively. These small declines appear to be recession related. Heating oil demand also dropped by 1 000 m^3/d to 12 000 m^3/d. Heavy fuel oil continued to account for a disproportionate share of the total decline, with consumption falling by 5 000 m^3/d to 22 000 m^3/d. The drop in HFO use was heavily concentrated in the industrial and electric power sectors of eastern Canada. Weak demand for jet fuel and asphalt resulted in a 3 000 m^3/d decline, to 43 000 m^3/d, in sales of 'other' products.

Figure 1 illustrates the trend in seasonally-adjusted monthly sales of refined products between 1986 and the first half of 1991. The figure shows that sales in 1991 have slumped to levels not seen since 1986.

Figure 1
Total Sales of Refined Products
(Seasonally adjusted)
000 m^3/d



2. Drilling and Exploration Activity

. *Despite a strong performance during the first quarter of 1991, drilling activity during the second quarter fell below industry expectations with field activity expected to remain depressed.*

The drilling industry was expected to record a modest turnaround in 1991. However, after experiencing the busiest winter in three years, as a result of higher crude oil prices during the latter half of 1990, second quarter drilling activity proved to be worse than expected with only 85 of 474 rigs reported active. This represents a rig utilization rate of only 18%.

Much of the pessimism surrounding the industry stems from the post war fall of crude oil and natural gas prices. This combined with rising production costs, relatively high interest rates, the strength of the Canadian dollar and provincial royalty policies continue to plague the industry. In fact, 1991 should prove to be the third consecutive money-losing year for an industry which is said to require a 55% utilization rate just to breakeven.

Nevertheless, on the strength of a strong first quarter performance, oil and gas well completions by the end of June had increased 6% over a year earlier to 2830 with total metres drilled up by 10%. Of this total, development wells increased by 20% to 1465 while exploration wells fell by 5% to 1365 wells.

The prolonged slump in the industry which has resulted in a continuing process of corporate concentration has also renewed calls for changes in current provincial royalty policies. Industry associations, citing dismal prospects for 1992, are again calling for a fundamental overhaul of royalty systems which for the most part are blamed for low levels of exploration and development activity.

A poor second quarter wiped out an encouraging start to 1991. Although activity is expected to increase over the last half of the year, drilling activity for 1991 is expected to fall below last year's 35% utilization rate to about 30% with the number of completed wells under 6000. The utilization rate for 1992 is expected to range between 28% and 30%.

Figure 2.1
Drilling Activity in Western Canada
(Number of Active Rigs)

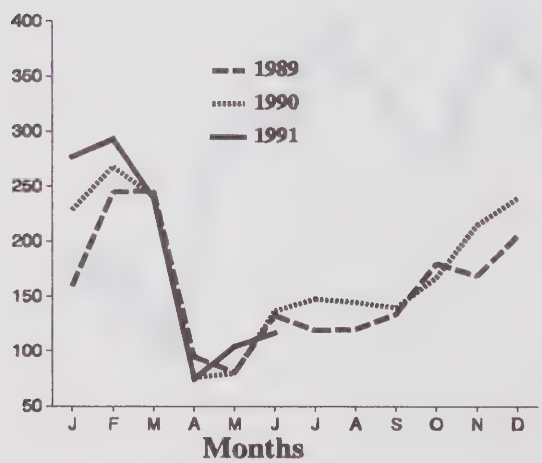
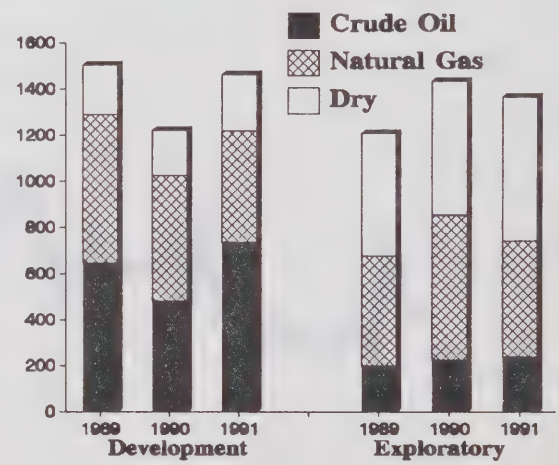


Figure 2.2
Well Completions
(January to June)



3. Crude Oil Supply

- *1991 has proved to be a difficult year for the Canadian oil industry with second quarter production falling to its lowest level in four years.*

- *The National Energy Board predicts that Canada could be dependent on offshore oil for about half of its light supplies by the year 2000.*

3.1 Total Crude Oil Supply

Total crude oil supply during the second quarter of 1991 averaged 339 000 m^3/d compared with 334 000 m^3/d a year earlier. The equivalent of 37% or 125 000 m^3/d of this supply was delivered to the export market.

Total domestic supply (including production from Ontario, recycled diluent, surplus Newgrade supply re-injected into the Interprovincial pipeline system and inventory change) averaged 265 000 m^3/d. Gross imports averaged 74 000 m^3/d.

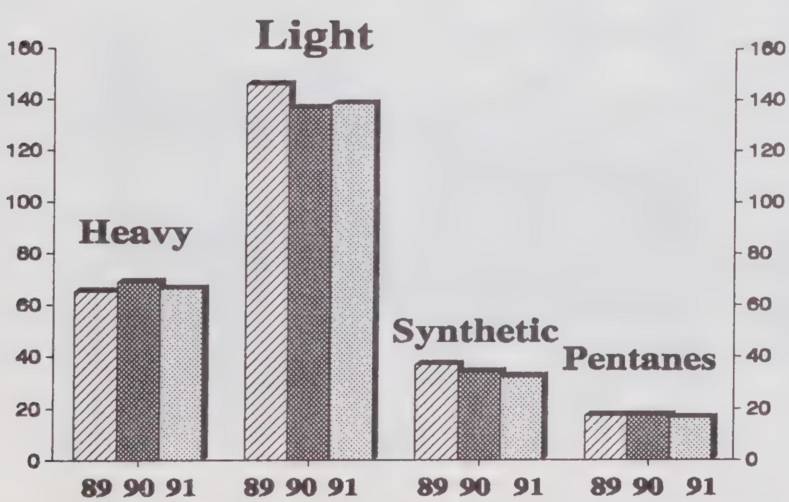
3.2 Domestic Production

Domestic production during the second quarter of 1991 averaged 254 000 m^3/d compared with 257 000 m^3/d a year earlier. A modest increase in conventional light crude oil output failed to offset a drop in heavy crude oil and bitumen production. A post war international surplus of heavier crudes combined with low prices resulted in the shutting in of some expensive heavy oil production.

Based on National Energy Board (NEB) estimates, 1991 production is expected to average 261 000 m^3/d, down 3 000 m^3/d from last year. Light conventional crude production at 139 000 m^3/d is expected to continue to decline with heavy crude oil and bitumen output also down.

Although Western Canada has excess heavy crude oil capacity, production and reserve additions of more valuable conventional light crude has been on the decline since 1988. The NEB [1)] forecasts that by the year 2000 production will fall nearly 45% to 83 000 m^3/d and fall an additional third by 2010.

Figure 3.2.1
Crude Oil Production
(Second Quarter)
000 m^3/d



The decline in domestic light crude oil production is expected to cause a reversal in Canada's net crude oil export position. In 1990, Canada was a net exporter of crude oil to the extent of 22 000 m^3/d. Net imports of light crude of 30 000 m^3/d were more than offset by net exports of heavy crude totalling 52 000 m^3/d.

With demand projected to increase modestly over the term of the NEB forecast, Canada is expected to become a net importer of 8 000 m^3/d of crude oil by 1995 and be dependent on offshore imports for nearly half of its light crude oil requirements by the year 2000 compared with about one third in 1990.

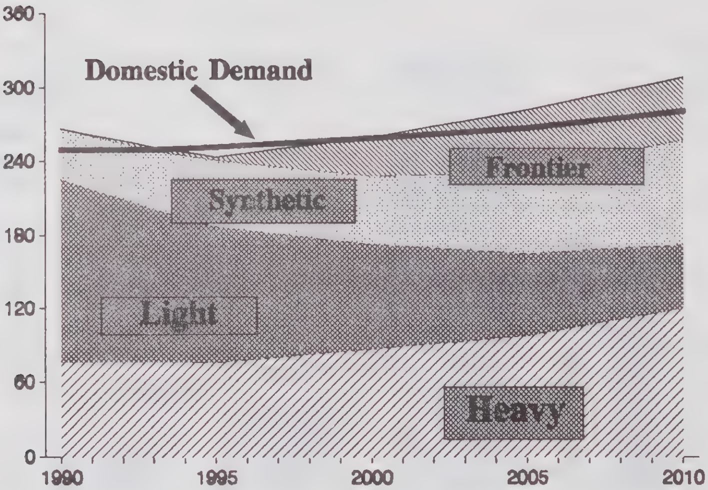
Refiners in Ontario, representing about 30% of total Canadian refining capacity, are expected to be most affected by this decline in domestic supply. Imports of light crude oil are projected to jump from 2 000 m^3/d in 1990 to 30 000 m^3/d by the year 2000, representing about 38% of the provinces light crude feedstock requirements.

Canada could return to a net export position of about 1 000 m3/d by the year 2000 and increase to about 28 000 m3/d by 2010. According to the NEB, this supply turnaround would depend on the development and production of costly northern frontier and offshore projects combined with a rise in synthetic crude oil output from mining and upgrading of heavy crude and bitumen.

This forecast suggests a significant change in the sourcing of domestic light crude oil supply. While conventional light crude from Western Canada currently contributes about 75% of total light crude supply it is expected to decrease to 48% in the year 2000 and to 32% by the year 2010.

The NEB suggests that there is considerable uncertainty associated with the development of additional light crude oil supply. These projects while considered technically feasible are particularly price sensitive and would require prices in the US$25 to US$35/bbl range to be economically viable.

Figure 3.2.2
Total Supply and Demand of Crude Oil And Equivalent
000 m^3/d



1) National Energy Board, Canadian Energy, Supply and Demand 1990-2010, September 1991.

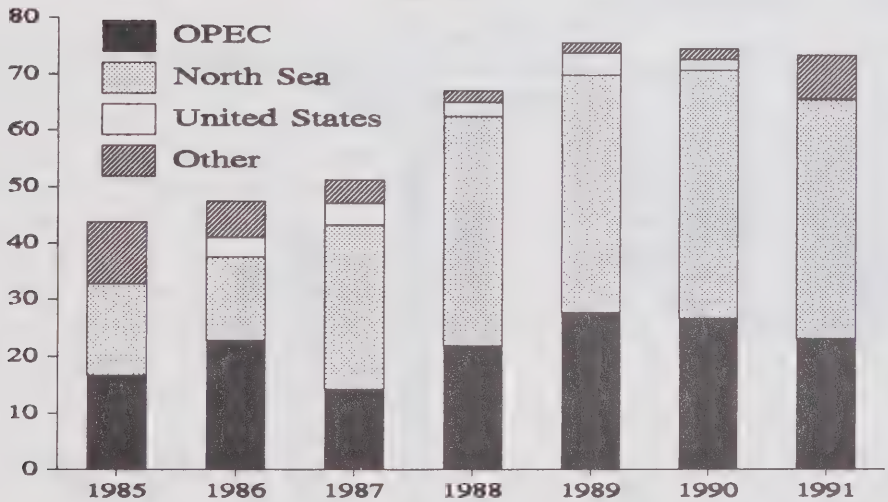
3.3 Crude Oil Imports

Deliveries of foreign crude oil to refineries in eastern Canada averaged 74 000 m^3/d during the second quarter of 1991, about 1 000 m^3/d below the corresponding period last year. Lower imports into the Atlantic and Ontario more than offset a rise in foreign crude deliveries to Quebec. The decline in the Atlantic stemmed from lower product sales in the region, as well as from a substantial draw on crude oil inventories. Imports into Ontario declined for essentially the same reason that they rose in Quebec, i.e. the closure of the Sarnia-Montreal pipeline in April. The closure effectively eliminated Quebec as a market for western Canadian crude oil (disregarding the small volume that was delivered to Montreal during the purging operation). All three refineries in Quebec will now rely almost exclusively on foreign crude oil although, potentially, the region could meet some of its future feedstock requirements from Canada's frontier areas.

Most of the surplus domestic crude generated from the the loss of the Quebec market was exported, with the remainder absorbed by the refineries in Ontario where imports were curtailed as a result.

North Sea crudes, averaging almost 43 000 m^3/d, accounted for 58% of imports, 60% of which were delivered to Quebec and the remainder to the Atlantic region. OPEC supplied about 23 000 m^3/d or 32% of total imports. Although refineries in the Atlantic remained the largest recipients of OPEC crudes, almost a third of OPEC deliveries went to Quebec, up from 5% last year. All of the incremental OPEC supply delivered to Quebec came from Venezuela and Nigeria. Saudi Arabia was the major source of OPEC crude in the Atlantic. The traditionally small volume of crude imports from the United States dwindled even further (to below 500 m^3/d) reflecting the cutback of imports into Ontario.

Figure 3.3
Crude Oil Imports by Source
(Second Quarter)
000 m^3/d



4. Crude Oil Disposition

. *Canadian refiners continued to curtail their demand for crude oil during the second quarter of 1991.*

4.1 Canadian Crude Oil Receipts

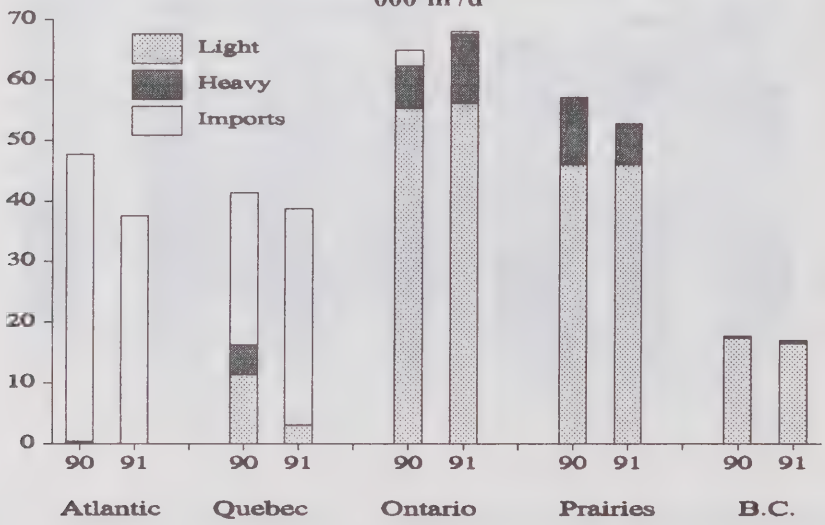
After peaking at close to 260 000 m^3/d in the final quarter of 1990, crude oil receipts fell by 28 000 m^3/d in the first quarter and then by another 17 000 m^3/d, to 214 000 m^3/d, in the second. This amounted to a drop of 14 000 m^3/d from the same period last year, and was, in fact, the lowest quarterly average since the second quarter of 1987.

Receipts are usually a little lower during the second quarter of the year because of refinery turnarounds. A spate of turnarounds may have been a factor behind this year's decline, although not likely the most important one since refinery crude runs, generally a better indicator than receipts of turnaround activity, declined only slightly from the year before. Rather, it would appear that the drop off in crude oil receipts was closely tied to the current slump in demand for refined products in Canada, which became clearly evident in the final quarter of 1990 but did not impact on domestic refiners' receipts until the following quarter.

This conclusion is supported by the fact that crude oil deliveries are forecast to be lower year-over-year for the remainder of 1991. Nevertheless, receipts might have fallen further had Canadian refiners been forced to bear the full brunt of the domestic slump in product sales. However, by displacing product imports in the domestic market and increasing sales in the export market, refiners have so far managed to offset perhaps as much as a half of the decline in product sales.

A 13 000 m^3/d drop, to below 141 000 m^3/d, in deliveries of domestic crudes accounted for virtually all of the decline in refinery receipts during the second quarter, imports being only marginally lower than last year. The decline in domestic crude deliveries largely reflected the closure and purging of the Sarnia-Montreal pipeline that got under way in April. Domestic heavy crude oil demand was also curtailed because of turnarounds and a decline in asphalt demand in the Prairies.

Figure 4.1
Refinery Crude Oil Receipts by Region
(Second Quarter)
000 m^3/d



4.2 Crude Oil Exports

Crude oil exports during the second quarter of 1991 averaged 125 000 m^3/d, almost 11 000 m^3/d more than a year earlier. However, exports were down from record highs recorded earlier in the year as Gulf war crude price and supply fears waned. Exports were also affected by the economic slowdown in North American and to a certain extent some temporary local market conditions such as spring refinery turnarounds.

The second quarter year-over-year jump in crude oil exports was primarily the result of an 8 000 m^3/d increase in light crude oil deliveries to 65 000 m^3/d. Heavy crude oil exports increased to 60 000 m^3/d. While light crude oil exports matched that recorded during the first quarter, heavy crude exports were down nearly 6 000 m^3/d.

Most Canadian crude oil exports are delivered to the United States with about 80% of this volume typically delivered to the U.S. midwest (PAD District II). During the second quarter of 1991 small volumes of heavy crude were shipped offshore through the port of Vancouver, via the Trans Mountain Pipe Line and its Westridge Marine Terminal, to Pacific Rim destinations.

Second quarter crude oil exports represented about 49% of domestic production (78% of blended heavy supply and 37% of net light crude oil supply) compared with 43% a year earlier. As a result of a drop in domestic demand crude oil exports exceeded imports by about 51 000 m^3/d compared with 43 000 m^3/d a year earlier.

Crude oil exports over 1991 are expected to average 120 000 m^3/d about 15 000 m^3/d higher than last year. Given that domestic production is expected to decline the volume of crude oil available for export will be determined by the extent of demand for indigenous production in the Canadian oil market.

Figure 4.2.1
Crude Oil Exports
000 m^3/d

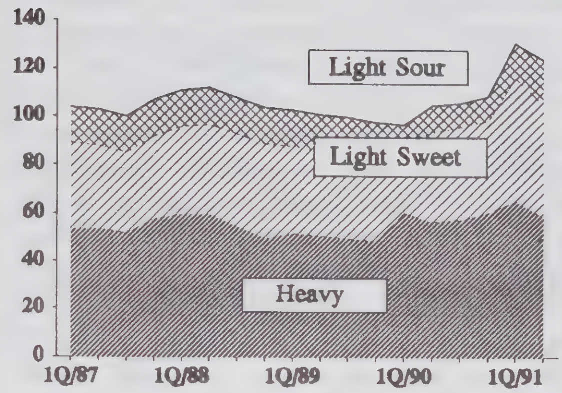
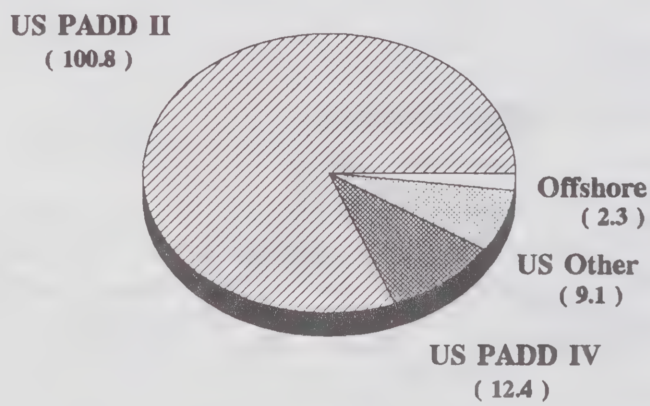


Figure 4.2.2
Crude Oil Exports by Destination
(Second Quarter)
000 m^3/d



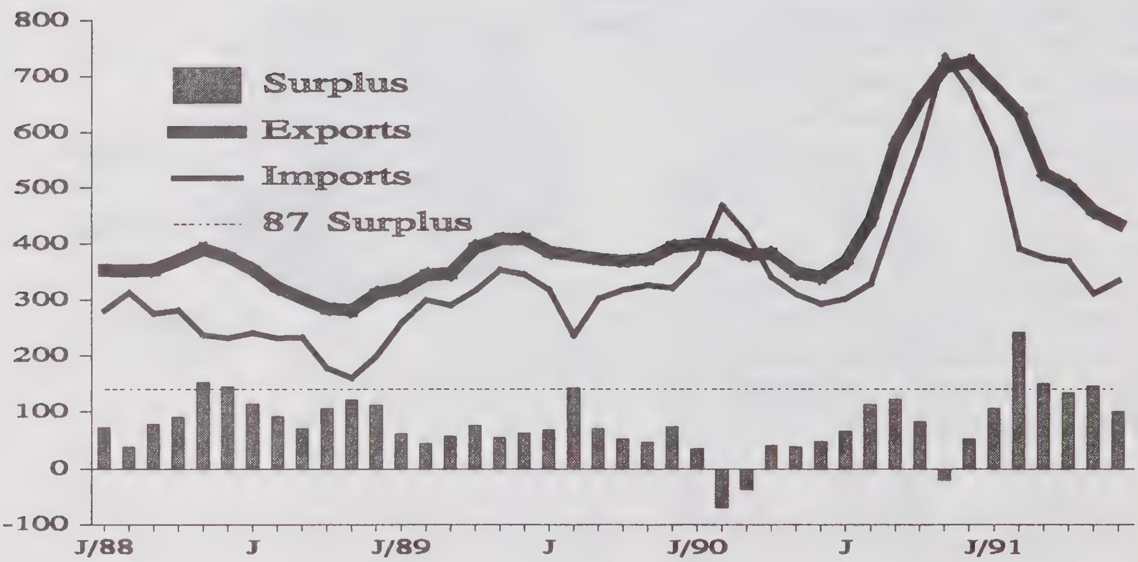
4.3 Trends in Canada's Crude Oil Trade

Canada both imports and exports crude oil. Within the context of a deregulated oil market,this two-way trade has been advantageous for primarily two reasons. First, not all the crude oil that western Canada produces can be refined domestically. Currently, only about a third of Canadian heavy crude oil production can be processed in Canada; while light crude oil production has been falling somewhat short of domestic requirements in recent years. This mismatch between the quality of crude produced and demanded has been resolved by exporting the excess supply of heavy crude oil, and offsetting the shortfall of domestic light crude supply through imports. Second, there appears to be no clear transportation cost advantage in having crude oil shipped from western Canada to those refineries in eastern Canada which have relatively easy access to offshore crudes. Indeed, transportation costs are minimized when the crude oil is sold to refineries relatively closer to the source of production, which in this case happen to encompass the refineries in the U.S. northern tier rather than those in eastern Canada. The transportation cost factor therefore helps explain why Canada typically trades more crude oil than warranted by supply/demand imbalances alone.

As a component of Canada's trade in visible goods, crude oil has not been large, typically accounting for less than 5% of the value of merchandise imports and exports. From being a fairly large net importer of crude oil in the early 1980's, Canada became a net exporter in 1983. The reversal reflected a sharp drop in domestic oil demand and, to a lesser extent, a recovery in domestic production. Since then, Canada has generally managed to maintain a rather thin surplus in its crude oil trade.

Figure 4.3.1 shows Canada's monthly trade balance in crude oil between 1988 and the first half of 1991. During most of this period, Canada ran a trade surplus with the value of its crude oil exports exceeding that of its imports. The surplus trended downwards in the first two years, before briefly becoming a deficit early in 1990; and then recovered completely by the first half of 1991.

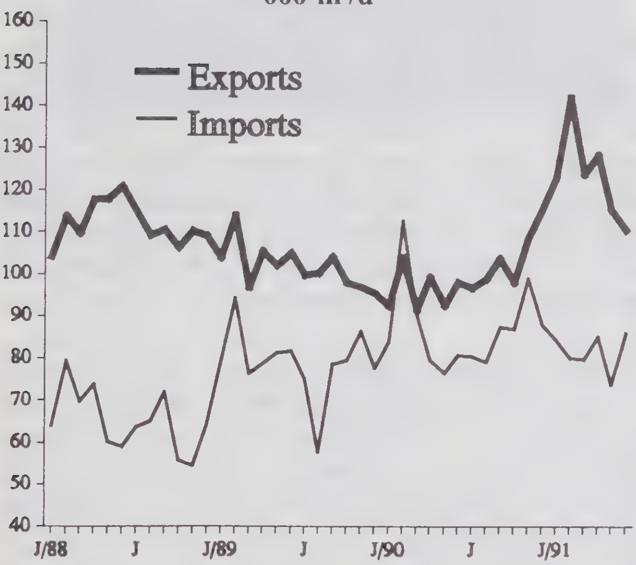
Figure 4.3.1
Value of Crude Oil Trade
millions of Cdn$



In fact, in the first half of 1991 the average surplus was about 10% higher than the average monthly surplus of \$140 million recorded in 1987 (indicated in Figure 4.3.1 by the dashed line).

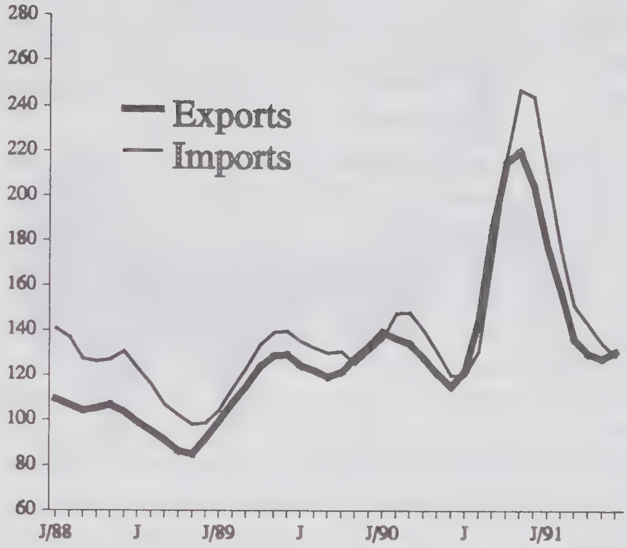
Crude oil trade values are simply a product of the volumes and the prices at which the oil is traded. Figures 4.3.2 and 4.3.3 show the trends in volumes and prices that underlie the changes in the value of trade during the period under review. Figure 4.3.2 shows a gradual convergence of export and import volumes up until around the end of 1990, at which point they abruptly diverge.

Figure 4.3.2
Crude Oil Trade, Volumes
000 m^3/d



As illustrated in Figure 4.3.3, the period was characterized by considerable price volatility, spanning both the collapse in oil prices in the latter half of 1988 and their sharp escalation during the Persian Gulf conflict two years later. It should be noted that export prices have usually been lower than import prices mainly because a much higher proportion of lower-valued heavy crude oil is exported than imported. (In fact, the differential between export and import prices shown in Figure 4.3.3 is likely underestimated by some \$5 to \$10/m^3 since imports are priced FOB at the port of exit.).

Figure 4.3.3
Crude Oil Trade, Prices
(\$Cdn/m^3)



Other things being equal, an increase in the price and/or volume of crude oil exports raises the surplus; while an increase in the price and/or volume of imports lowers it. The converse also applies. Figures 4.3.4 and 4.3.5 quantify, in dollar terms, the impact that these volumetric and price changes have had on the trade surplus. All changes are measured against the average monthly trade volumes and prices of 1987.[1] The 'net effect' lines in the two figures indicate the net impact that these volume and price changes have had on the trade balance. Upward movements in these lines are surplus-raising, and conversely.

A comparison of Figures 4.3.4 and 4.3.5 shows that, since 1987, the deterioration, and more recently the recovery, in Canada's crude oil trade balance has primarily reflected volumetric changes. Trends in prices have had a relatively minor influence on the value of the surplus given that Canada is but a small net exporter of crude oil; and export and import prices move closely in tandem with one another. Thus, any effects that changes in export prices would have on the surplus would be largely negated by similar changes on the import side.

Figure 4.3.4
Volume Effects on Crude Oil Trade
millions of $Cdn

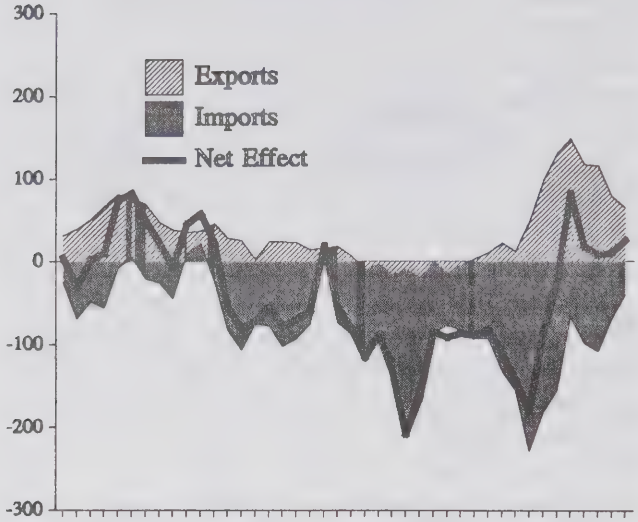
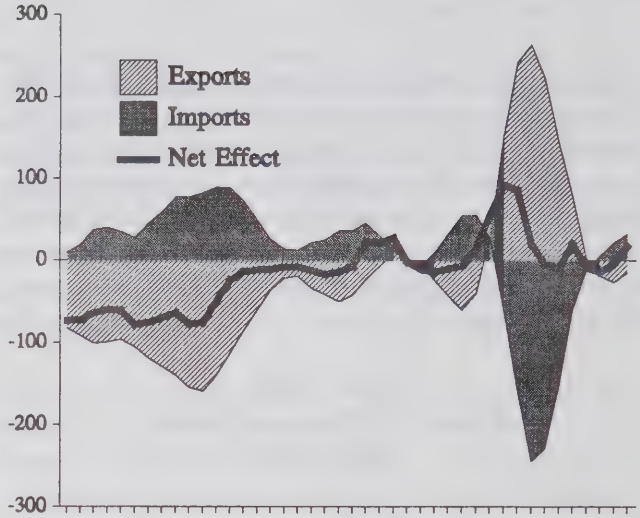


Figure 4.3.5
Price Effects on Crude Oil Trade
millions of $Cdn



Nevertheless, the drop in world oil prices in 1988 did exert some downward pressure on the surplus, partly because net exports happened to be at relatively high levels at the time. However, another factor was a significant rise in the price differential between exports and imports which occurred in part because Canadian producers were offering price discounts on exports to compensate for IPL pipeline constraints. The net price effect in Figure 4.3.5 indicates that the average monthly surplus in 1988 would have been almost $75 million higher had prices stayed at their 1987 averages.

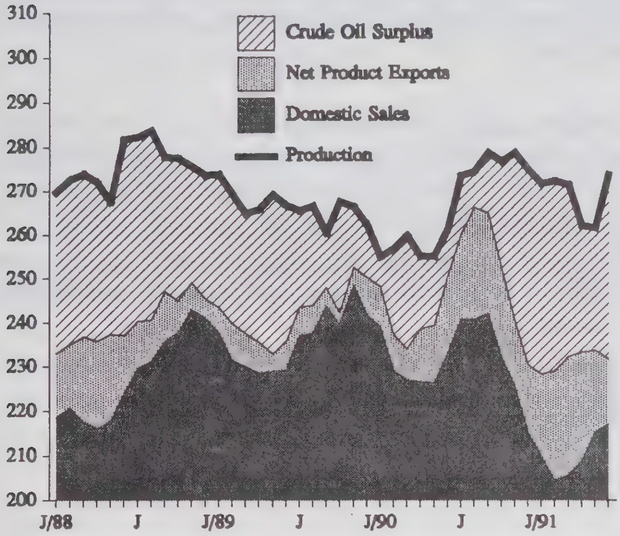
Oil prices recovered and, coincidentally, the price differential between exports and imports narrowed, around the start of 1989. Prices then remained relatively stable up until the onset of the Persian Gulf conflict, having little bearing either way on the value of the trade surplus. The dramatic rise in prices during the Gulf conflict was initially surplus-raising, as might be expected. However, this was soon dissipated by a substantial widening of the differential between import (mostly North Sea) and export prices. Import prices rose by much more because of an upward shift in demand for these crudes in Europe, whose traditional oil supply lines were more affected by the embargo imposed on Iraqi and Kuwaiti crudes.The situation was later exacerbated and prolonged by discounts offered on Canadian exports as a result of reduced capacity and apportionment on the IPL system .

As suggested above, the changes to the value of the surplus have generally been volumetric in origin. This has particularly been the case since 1989. Figure 4.3.4 indicates that most of the decline in the surplus reflected rising imports rather than falling exports. On the other hand, the eventual recovery in the surplus was manifested by a rise in exports and a fall in imports.

Trends in Canada's volumetric crude oil trade surplus are closely tied to developments in the domestic oil sector. Figure 4.3.6 illustrates, in an approximate way, the trade surplus as the residual of domestic crude oil production less domestic refined product demand and net product exports. The gradual narrowing of the volumetric surplus during 1988 and 1989 resulted from both declining oil production on the one hand, and rising oil demand on the other.

The trade deficit in the first quarter of 1990 largely came about because of a drop in output at Syncrude after an explosion and fire damaged the plant towards the end of 1989. This had little effect on exports but raised imports into central Canada considerably, to the point where Canada briefly became a net crude oil importer in February.

Figure 4.3.6
Oil Production, Demand and Net Product Exports
000 m3/d



Crude oil imports stayed high during the remainder of 1990 despite the return to full production at Syncrude and a softening of demand in the Canadian oil products market. One reason was that refiners in eastern Canada, where all the importing is done, were able to maintain sales by displacing product imports in the domestic market and selling more in the export market. This generated a significant improvement in Canada's trade surplus in refined products. Another reason was the large shift away from domestic crudes towards imports by the Montreal refiners in the fourth quarter. However, this also led to a concommitant rise in exports as deliveries that would have otherwise gone to Montreal were now diverted to the export market. Exports also grew because the sharp increase in oil prices during the Persian Gulf conflict provided an added stimulus to domestic oil production. Demand for refined products in Canada fell sharply in the final quarter of 1990, mainly reflecting the recession and higher oil prices.Domestic refiners, apparently not anticipating the extent of the decline, maintained crude oil receipts and runs at relatively high levels during the quarter. With excessive inventories at the end of the year, and the expectation that the slump in product demand would continue, refiners cut back sharply on their crude receipts around the start of 1991.

Domestic crudes which were surplus to refiners' requirements were exported, while imports were curtailed. As suggested in Figure 4.3.4, the rise in the surplus in the first half of 1991 to levels not seen since 1987 was effectively due to this increase in the volume of exports over imports.

Since this review makes only passing reference to Canada's trade position in refined products, it provides an incomplete picture of the extent of the country's self-sufficiency in oil. Figure 4.3.6 shows that from early 1990 on, considerable gains were also made in the oil products surplus, which would suggest that Canada had become even more self-sufficient than indicated by the trade figures for crude oil alone. Nevertheless, the recent improvement in Canada's overall oil trade balance is not that encouraging since it did not so much arise from sustainable gains in productive capacity as from a recession-induced drop in oil demand. With oil prices and domestic production now down to pre-conflict levels, and the economy presumably recovering, it is expected that the surplus will resume the gradual decline that was temporarily interrupted by the Gulf conflict and the recession.

Notes:

1.This review is mostly based on Canada Customs data published by the International Trade Division of Statistics Canada. It should be noted that the volume and (derived) price data sometimes differ significantly from those reported by other government bodies and the industry. Nevertheless, the trends found when Customs data is used are roughly consistent with the trends based on other data sources.

2.The relationship between Figures 4.3.4 and 4.3.5 and Figure 4.3.1 is straightforward: adding the monthly volume and price effects of exports to the average monthly value of exports (about $405 million) in 1987, generates the line showing the value of exports in Figure 4.3.1. Similarly, the value of imports can be derived by inverting the volume and price effects of imports and adding these to the average monthly value of imports in 1987 (about $ 265 million).

5. Pipelines Deliveries

. *Trans Mountain Pipe Line deliveries during the second quarter were down substantially from the previous quarter.*

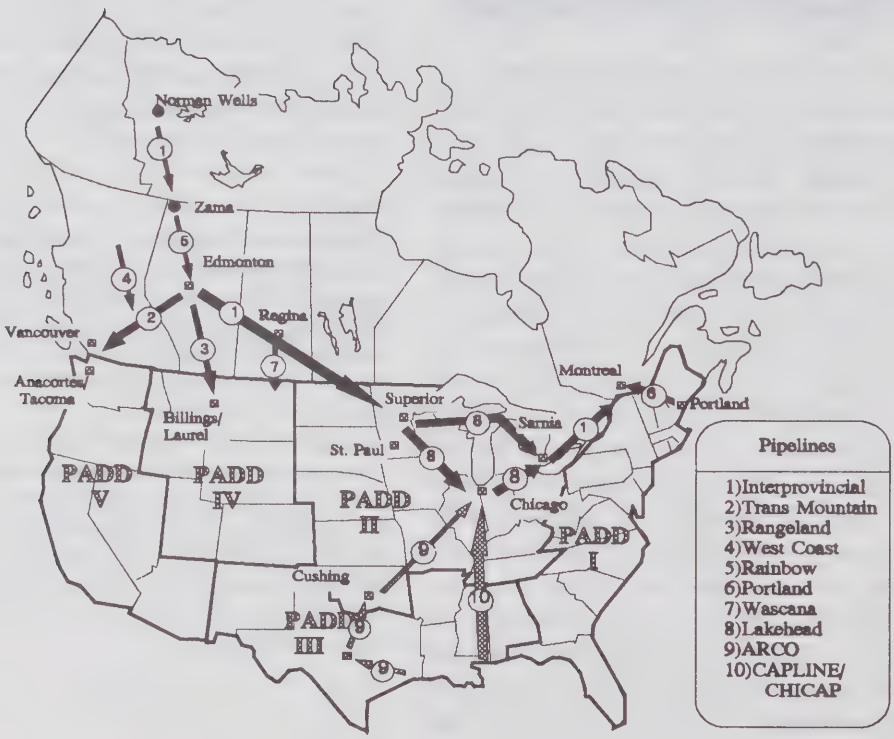
. *Interprovincial Pipe Line is now considering options for its closed Sarnia-Montreal extension.*

Most Canadian crude oil is gathered at Edmonton, Alberta. It is then delivered to the domestic and export market, for the most part, by a network of pipelines.

The bulk of Canadian exports are delivered to the United States, via the Interprovincial and Lakehead pipeline systems. Smaller volumes are delivered by the Trans Mountain Pipe Line to the west coast for shipment to U.S. refineries and tankering offshore. The Rangeland pipeline supplies U.S. refiners south of Edmonton.

Canadian crude competes in the U.S. midwest, in particular, in the Chicago refining area, with indigenous U.S. crudes and other foreign crudes delivered directly through the CAPLINE/CHICAP pipeline system from the Louisiana, Gulf Coast and alternatively the Arco pipeline system from the Texas, Gulf Coast via Cushing Oklahoma.

Figure 5.
Major Crude Oil Pipelines



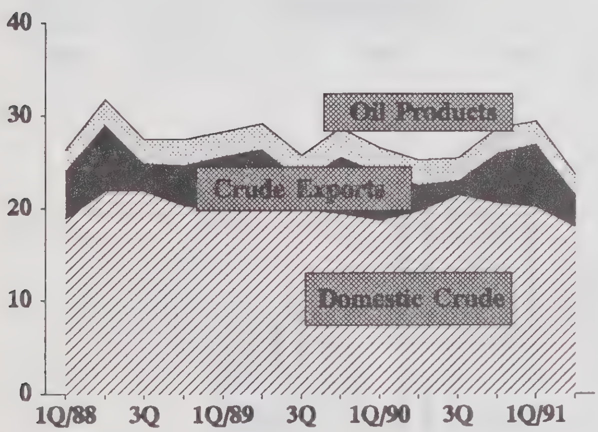
5.1 Trans Mountain Pipe Line Deliveries

The Trans Mountain Pipe Line (TMPL) originates in Edmonton and delivers crude oil and product some 1328 kilometres west to Vancouver. The pipeline also receives British Columbia crude delivered to Kamloops, B.C. via the Westcoast pipeline.

Crude oil and product deliveries during the second quarter of 1991 averaged 24 000 m^3/d with about 10 000 m^3/d of spare capacity. Total deliveries were down from both the first quarter and a year earlier. The decline was for the most part the result of a drop in semi-refined product throughput.

While domestic deliveries of crude oil to Vancouver held at about 14 000 m^3/d, second quarter deliveries of semi-refined products at 4 000 m^3/d were 1 000 m^3/d below a year earlier. Deliveries of refined products from Edmonton to Kamloops fell slightly to 2 000 m^3/d.

Figure 5.1
Trans Mountain Pipe Line Deliveries
000 m^3/d



5.2 Interprovincial Pipe Line Deliveries

The Interprovincial Pipe Line (IPL) system, consists of three major sections stretching some 3 700 kilometres from Edmonton, Alberta to Montreal, Quebec.

The western section originates at Edmonton travels east through Regina, Saskatchewan and crosses into the United States near Gretna, Manitoba. The Lakehead Pipe Line Company operates the American portion of the line which serves markets in the U.S. Great Lakes area. The eastern section from Sarnia to Montreal provides for the delivery of western crude to eastern markets.

Following a leak on the Gretna to Superior Wisconsin portion of the Lakehead pipeline (line 3) last March, spilling more than 6 000 m^3 of oil near Grand Rapids, Minnesota, the US Department of Transport imposed pressure restrictions on the line, which has a capacity of about 105 000 m^3/d, and directed IPL to conduct pressure tests.

The first test of a six phase hydrostatic test program which began late in July 1990 led to three ruptures and the closure of line 3 for about a week. IPL expects sectional testing to be completed by the end of 1992.

Throughput on the Sarnia-Montreal pipeline began to decline late in 1990 as domestic crudes delivered to Montreal became generally uncompetitive with offshore crudes. Shippers advised IPL that they intended to terminate deliveries of domestic crude during the first quarter and as a result IPL began to plan for line idling and deactivation. By August, IPL had drained the remaining crude from the line and announced its closure.

Nevertheless, total IPL deliveries during the second quarter of 1991 averaged 226 000 m^3/d compared with 221 000 m^3/d a year earlier. Deliveries to Canadian refineries fell by 11 000 m^3/d to 113 000 m^3/d. The decline, most of which occurred in Quebec, was offset by a 15 000 m^3/d rise in exports. Exports averaged 113 000 m^3/d compared with 98 000 m^3/d last year.

A number of options are now being considered by IPL for the now-closed line. They include periodic shipment of small volumes of heavy crude oil from western Canada to Montreal and line reversal to move imported crude from Montreal to Sarnia. IPL is also considering using the line to transport under low pressure natural gas.

With the pending closure of the Sarnia-Montreal pipeline, refiners in Montreal became increasingly dependant on imported crude. Domestic deliveries during the second quarter fell by 13 000 m^3/d to about 4 000 m^3/d. This drop was nearly matched by a 11 000 m^3/d increase in crude oil imports to 36 000 m^3/d.

Figure 5.2.1
IPL Deliveries
000 m^3/d

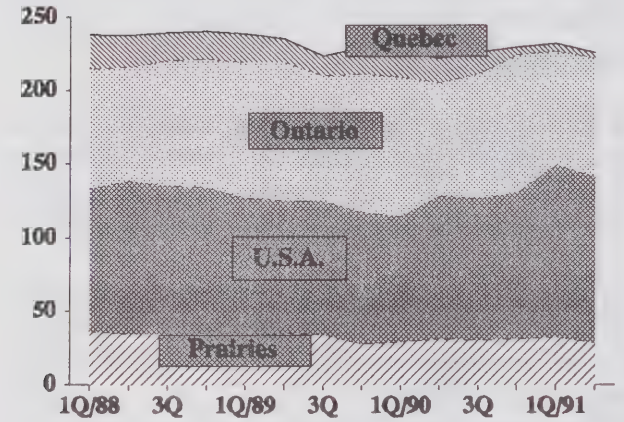
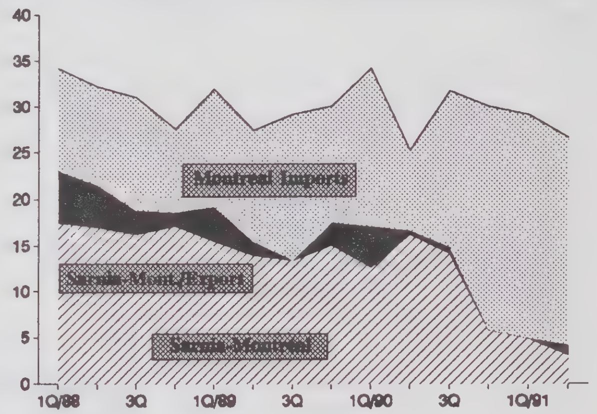


Figure 5.2.2
Deliveries to Montreal
000 m^3/d



6. Refinery Throughput and Utilization Rates

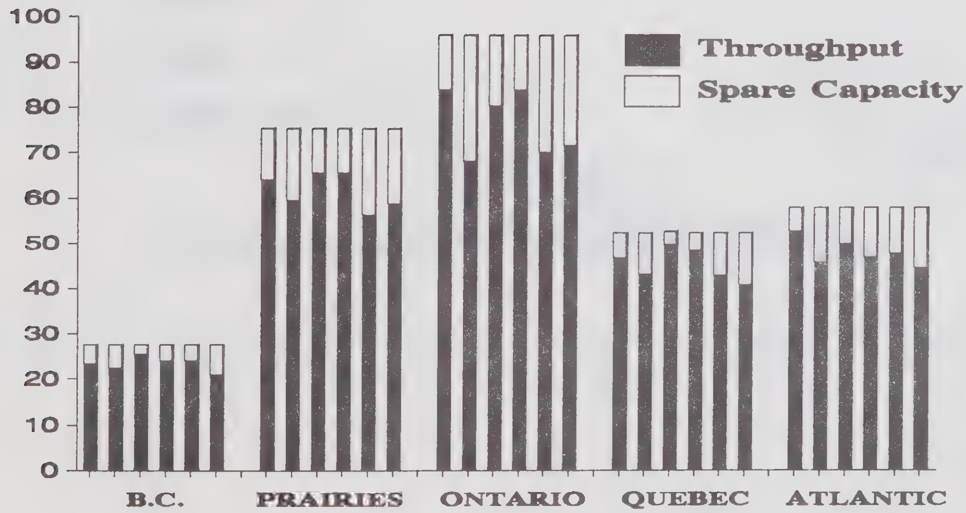
. The national refinery utilization rate averaged about 77% during the second quarter. The utilization rate varied little from one region to another.

Refinery throughput will normally diverge from refinery crude oil receipts for two reasons. First, feedstocks other than crude oil are also charged in the refining process. Some of the 'other' feedstocks include gas plant butanes (used mostly by Prairie refineries) and partially processed oil (used mostly by B.C. refineries). During the second quarter of 1991, these 'other' receipts averaged 17 000 m^3/d or about 7% of total refinery throughput in Canada.

Second, refinery throughput reflects changes in feedstock inventories. Other things being equal, an inventory drawdown will cause refinery throughput to exceed receipts - and vice versa in the case of an inventory build. Over the quarter, crude oil inventories at the national level were drawndown at a rate of almost 7 000 m^3/d.

Total throughput averaged 238 000 m^3/d during the second quarter, about 2 000 m^3/d below the same quarter the year before. With estimated Canadian refining capacity now up by about 4 000 m^3/d to almost 310 000 m^3/d, (due to capacity expansions last year at refineries in Quebec and the Prairies), this level of throughput corresponded to a national refinery utilization rate of about 77%. On a regional basis, the utilization rate ranged from 75% in Ontario to 78% in the Prairies. The figure below illustrates refinery throughput and capacity by region, starting from the first quarter of 1990.

Figure 6.1
Refinery Utilization vs Capacity
(1st Quarter 1990 to 2nd Quarter 1991)
000 m^3/d



7. Stocks

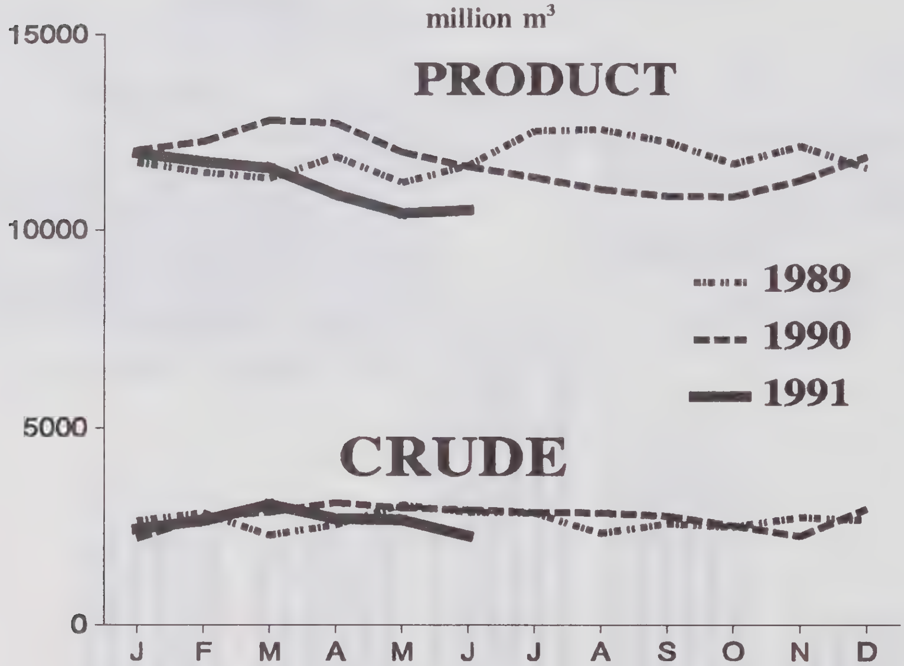
. *Crude oil and petroleum product inventories were adjusted downward as a result of low demand for refined products.*

Primary stocks of crude oil and refined petroleum products closed the second half of 1991 at 12.8 million m^3, 12% lower than a year earlier. Of this volume, refined petroleum products accounting for 82% of this total, fell 9% to 10.5 million m^3. Crude oil stocks were 23% lower at 2.3 million m^3 but remained within normal operating levels.

Stocks of 'main' petroleum products, representing about 70% of total refined products were down 5% from the year before to 7.3 million m^3. Other refined products including such items as jet fuel, petrochemical feedstocks and asphalt fell 19% to 3.8 million m^3.

End of June stocks were 13% lower than the close of the previous quarter. Refiners reduced crude runs in April and May and allowed refined product inventories to decline. Although crude runs increased in June after the completion of spring maintenance programs product inventories only edged up slightly.

Figure 7.1
Crude Oil And Petroleum Product Stocks
million m^3



The following graphs illustrate the end-of-month stock levels for selected refined petroleum products.

By the end of June total crude oil and petroleum product stocks represented about 53 days of forward supply, 9 fewer than a year earlier. If the Atlantic region is excluded from the calculation because a large portion of its supplies are exported the number of days of supply would be reduced to 48 days.

Stocks referred to in this section do not include estimates of crude oil held in pipeline tankage. If these stocks were to be included it is estimated that the number of days of forward supply would increase by about seven days to 60 days.

Figure 7.2
Motor Gasoline Stocks
million m³

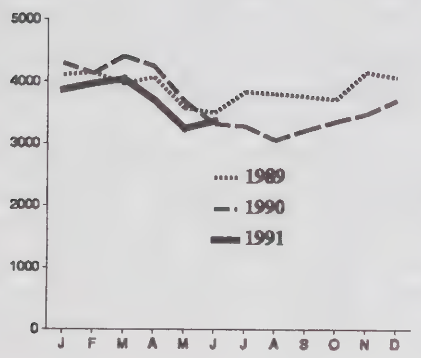


Figure 7.3
Middle Distillate Stocks
million m³

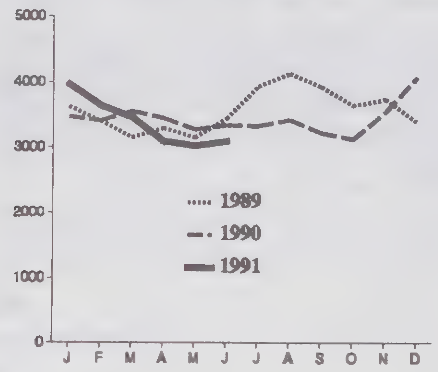


Figure 7.4
Other Refined Petroleum Product Stocks
million m³

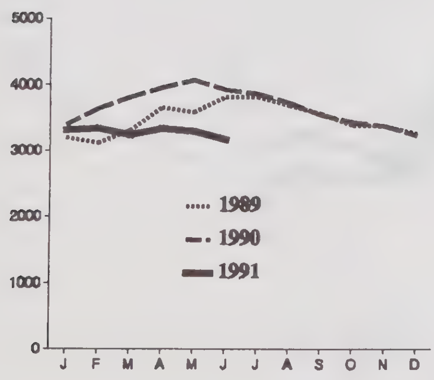
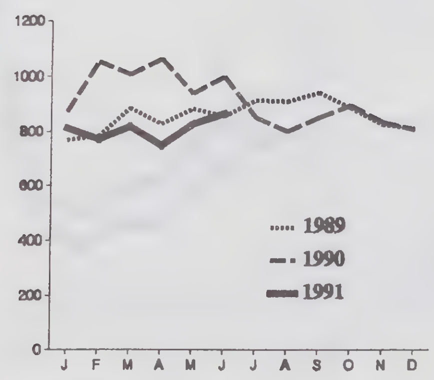


Figure 7.5
Heavy Fuel Oil Stocks
million m³



8. Crude Oil and Petroleum Product Prices

. *Weak international and domestic crude oil and petroleum product prices largely reflected the economic recession.*

. *The differential between Canadian light crude, sour and heavy crudes have fallen near levels observed prior to the onset of the Gulf crisis.*

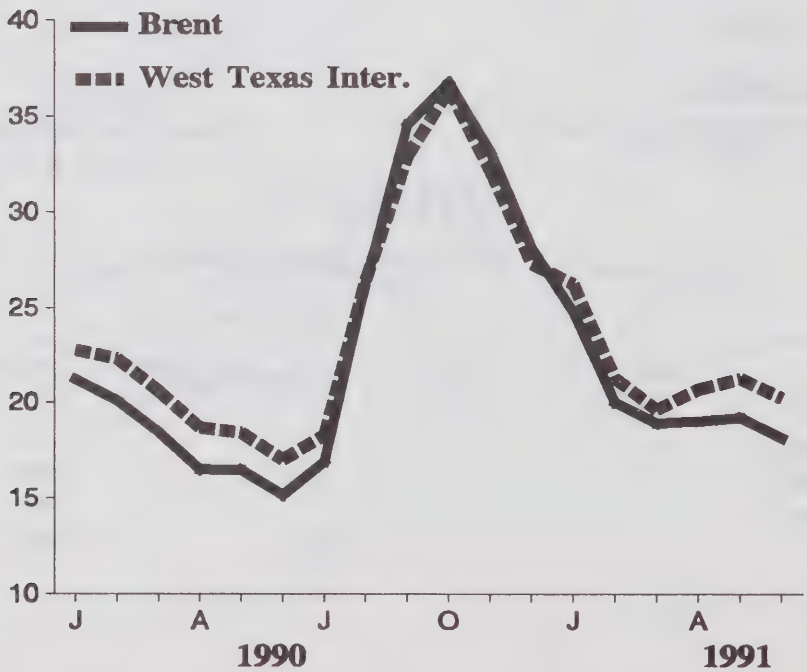
8.1 International Crude Oil Prices

Spot crude oil prices were extremely volatile over the first quarter of 1991. The prominent factor affecting prices was the conflict in the Persian Gulf. However, the effects of slow economic growth in industrialized countries (primarily the United States, and the United Kingdom), lower oil demand, increased conservation efforts, and a well-supplied oil market also helped keep prices off-balance.

As a result, over the first quarter of 1991, West Texas Intermediate (WTI) averaged $22.35/bbl, an increase of $0.45/bbl from the first quarter 1990 level. Nevertheless, this marked a dramatic decline from the fourth quarter of 1990, when WTI averaged $31.95/bbl.

Crude oil prices weakened significantly during the second quarter of the year, with WTI averaging $20.75/bbl, $1.60/bbl below first quarter levels. Declining prices largely reflected the economic recession which lingered throughout the first six months of 1991 and which effectively dampened demand for oil products. Further weakening crude oil prices were the availability of crude oil supplies, floating oil stocks held by Saudi Arabia and Iran, and continuing high OPEC production.

Figure 8.1
International Crude Oil Prices
US$/barrel



8.2 Domestic Crude Oil Prices

The price for Edmonton par crude (40°API, 0.5% sulphur), as posted by refiners, during the second quarter of 1991 averaged $22.67/bbl. The price of the domestic benchmark crude has been on the decline since October of 1990 when international market uncertainties leading-up to the Persian Gulf conflict pushed the price up to a record high of $40.65/bbl.

Edmonton par crude competes directly with West Texas Intermediate (WTI), the U.S. benchmark light sweet crude, and a close price relationship exists. The differential between these two crudes typically falls between US$0.25 and $0.40.bbl in favour of WTI. During the fourth quarter of 1990 the price differential narrowed to $0.14/bbl. However, since the end of the war, it has returned to within the traditional range with a second quarter average of US$0.34/bbl.

The average price for all crude and equivalent purchased in Alberta at main trunk line inlets (Edmonton or Hardisty) for domestic use during the second quarter of 1991 averaged $20.89/bbl. This compares with $34.50 recorded during the fourth quarter 1990.

On average the quality of light conventional crude oil purchased during the second quarter was 37.5° API and 0.47% sulphur. Blends of heavy crude oil averaged 24.2° API, 2.61% sulphur.

The differential between light and heavy crude reached a high of almost $9.00/bbl during the first quarter in part due to the oversupply of heavier crudes on the international market and falling demand for petroleum products. (See Figure 8.2.2)

Although consistent with international prices, the light/heavy differential on the domestic scene was further exacerbated by shipping constraints on the Lakehead portion of the IPL and the closure of the Sarnia-Montreal pipeline.

Nevertheless, the outlook for domestic heavy crude producers has improved somewhat after a dismal winter. Since March, heavy crude oil prices have increased by about a $1/bbl and the differential between heavy and light crude decreased. During the second quarter the differential narrowed to $7.78/bbl compared with a first-quarter average of $8.19/bbl.

Figure 8.2.1
Canadian Par Crude Postings
$/bbl

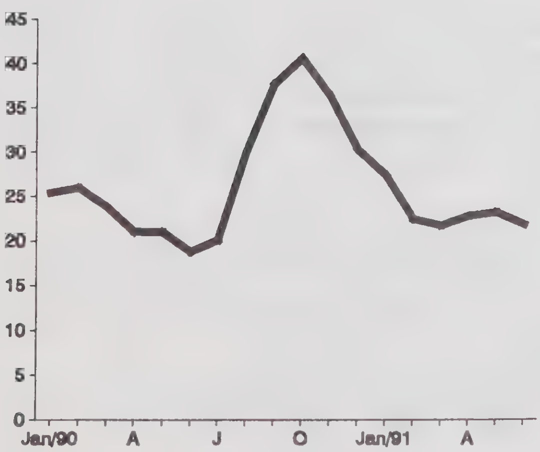
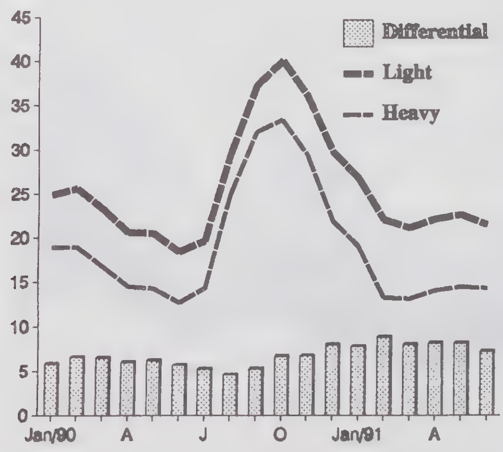


Figure 8.2.2
Light and Heavy Purchase Prices
$/bbl



8.3 Export Prices

A comparison of light crude oil export prices and Edmonton par crude for the second quarter of 1991 was not available at printing.

A complete review of second and third quarter 1991 export prices will be included in the next issue of this report.

8.4 Domestic Crude Oil Price Differentials

The following figure illustrates the price differentials between Edmonton par crude oil and the average posted price of Alberta light sour crude and bitumen.

After increasing significantly over latter half of 1990, differentials during the second quarter of 1991 have fallen almost to the levels observed prior to the onset of the Gulf crisis.

During the second quarter, the average Edmonton par crude to bitumen price differential decreased by \$0.81/bbl to \$13.73/bbl. Similarily, the Par to light sour crude differential decreased \$0.78/bbl to \$3.75/bbl.

8.5 Petroleum Product Prices

During the second quarter of 1991, the price of regular unleaded gasoline averaged 55.7 cents per litre, a decrease of 3.2 cents per litre over the first quarter average. Although the second quarter 1991 pump price is 9.2 cents per litre above the second quarter 1986 price, when the tax included pump price is adjusted for inflation, it has declined 2.6 cents per litre or 5.6% over the five-year period.

The rapid decline in prices over the first quarter of 1991, following the price peaks due to the Persian Gulf crisis, continued through the early part of the second quarter. However, the trend reversed in May and June for gasoline, stabilizing at pre-invasion prices.

In the Maritime provinces, gasoline prices fell gradually over the second quarter, contrary to the Canadian average. All other cities surveyed, except Regina, recorded increases from the low prices recorded at the beginning of the second quarter.

Figure 8.4
Par vs Heavy and Sour Price Differentials
\$/bbl

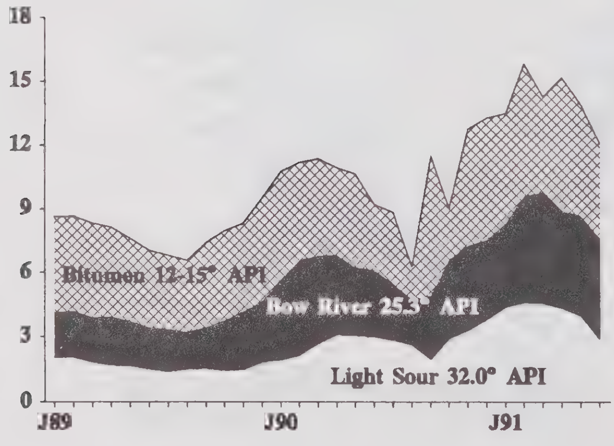
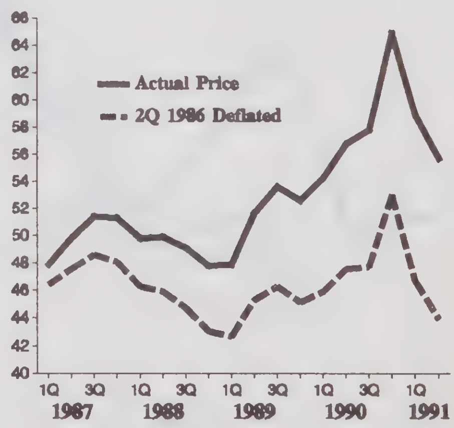
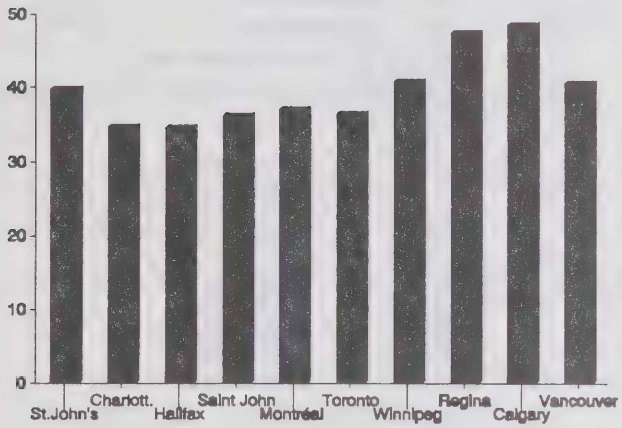


Figure 8.5.1
Regular Unleaded Gasoline Prices
cents per litre



Diesel and residential furnace fuel oil prices declined more slowly than gasoline. At the end of the second quarter, the price of diesel averaged 56.3 cents per litre, dropping 0.8 cents per litre from the end of the first quarter. Residential furnace fuel oil maintained 36.8 cents per litre throughout June dropping 3.3 cents from the end of first quarter. Unlike gasoline, both diesel and furnace fuel oil did not fall to pre-invasion prices.

Figure 8.5.2
Average Consumer Furnace Oil Prices
(End of June)
cents per litre



Consumption Taxes on Petroleum Products

Consumption taxes on regular unleaded gasoline averaged 23.7 cents per litre during the first quarter of 1991 and 24.7 cents per litre during the second quarter of 1991. The increase was solely due to provincial tax increases (1.1 cents per litre), while the federal component of the tax decreased 0.1 cent per litre.

Several provincial budgets resulted in changes to consumption taxes on gasoline and diesel, most of them coming into effect during the second quarter of 1991. Alberta raised its tax on gasoline and diesel by 2 cents per litre to 9 cents per litre. Manitoba increased its gasoline tax 1.5 cents per litre and its diesel tax 1 cent per litre. Both Quebec and Ontario imposed tax increases on gasoline and diesel with the increases being phased in at several stages throughout the year.

The ad valorem tax system was lifted in NewBrunswick and fixed rate taxes were imposed. While Newfoundland continued with the ad valorem system, a one-year freeze on taxes has been imposed. Both provinces have fixed their tax at their highest levels.

Between May 1, 1990 and May 1, 1991, the effect of these budgetary measures and the regular adjustments to taxes in those provinces which levy ad valorem taxes was a 1.5 cents per litre increase in the average provincial tax on regular unleaded gasoline and a 1.7 cents per litre rise on diesel.

The drop in federal taxes is attributable to the Goods and Services Tax (GST) which replaced the Federal Sales Tax (FST). Being an ad valorem tax, the GST decreases as the product prices decrease, thereby reducing the federal component of the taxes when product prices are lower.

Canada vs United States

In Canada, the gradual price decline after the Persian Gulf crisis continued into the early part of the second quarter whereas in the U.S., prices commenced to move upwards in April. As a result, the price spread between the two countries narrowed in April (18.6 cents per litre) from 22.6 cents per litre in March. The average price spread between the two countries was 22.5 cents per litre during the first quarter of 1991 while the second quarter recorded an average of 19.6 cents per litre.

A large proportion of the spread is attributable to higher taxes in Canada. During the first quarter, taxes accounted for 62.4% of the price differential between Canada and the U.S. while during the second quarter it was 76.3%, provincial tax increases in Canada being the cause.

The crude cost component of gasoline in Canada plunged from 19 cents per litre in March to 13.7 cents per litre in June largely due to the oversupply situation that existed following the Gulf war and the declining demand for petroleum products. In the U.S., the crude cost component dropped two cents per litre from March to 13.4 cents per litre in June, narrowing the crude cost differential between the two countries to just 0.3 cents per litre at the end of the quarter.

Refining and marketing costs and retail margins increased steadily during the second quarter in Canada while in the U.S., there was a slight drop at the end of the quarter. As lower priced U.S. gasoline competed vigorously with Canadian supplies, inventories of petroleum products increased, particularly in Ontario.

Thus there was a sustained increase in refining and marketing costs in Canada with declining revenues. The differential in the 'refining and marketing costs and margins' component of the gasoline price between the two countries doubled from the end of the first quarter to the end of the second quarter.

Figure 8.5.3
Average Retail Price of Motor Gasoline
(Canada vs United States)
cents per litre

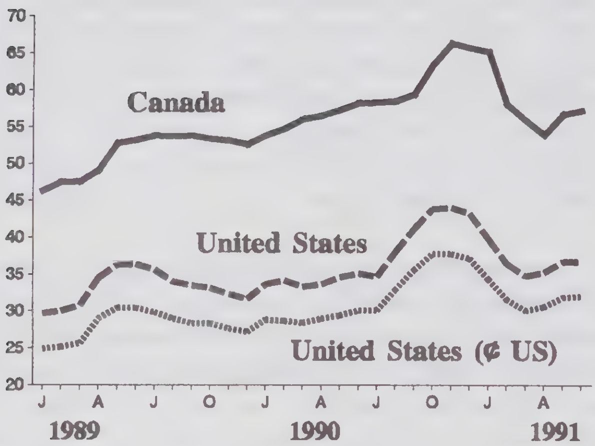
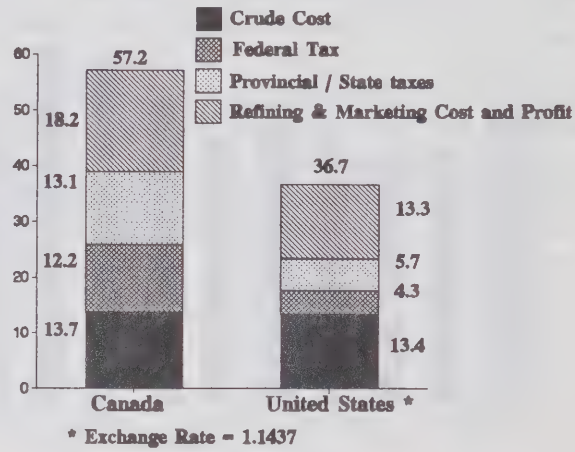


Figure 8.5.4
Breakdown of Average Pump Price
(June 1991)
cents per litre

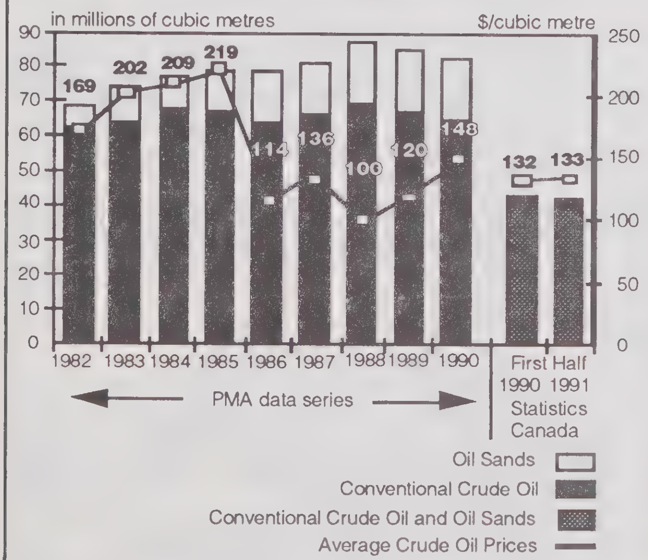


9. Financial Performance of the Canadian Oil and Gas Industry: First Half 1991

The following section was prepared by the Petroleum Monitoring Agency (PMA). Further information is available from V. Stanciulescu (613) 995-2100 and F. Laberge (613) 996-8035.

- *Internal cash flow decreased 19% to $2.5 billion in the first half of 1991 from $3.1 billion in the corresponding 1990 period.*
- *Net income after unusual items fell $1.2 billion from a profit of $615 million in the first half of 1990 to a loss of $565 million in the corresponding 1991 period.*
- *Gross capital expenditures increased 21% to $3.9 billion in the first half of 1991 with a rise in the reinvestment rate to 153% from 102% in the corresponding 1990 period.*
- *Dividend payments in the first half of 1991 increased 8% to $675 million from $625 million.*
- *The petroleum industry's annualized rate of return on capital employed for the for the first half of 1991 was 2.3% vs. 4.6% for the corresponding 1990 period.*
- *Long-term debt as a percentage of capital employed increased to 42% from 39% at the end of 1990.*

Figure 9.1 Crude Oil Volumes and Average Prices: 1982 - 1991



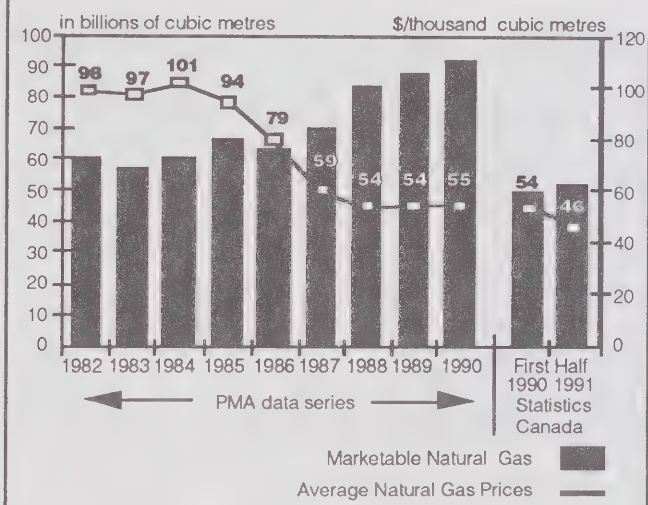
Total sales revenues decreased 1% to $20.7 billion in the first half of 1991 from $20.9 billion in the corresponding 1990 period.

While international crude oil prices increased by approximately 7% in the first half of 1991 vs. the corresponding 1990 period, prices realized by Canadian producers may not have fully benefitted from the rise due to:

1. the Canadian dollar strengthening against the U.S. dollar. International oil prices are generally quoted in U.S. dollars and as the Canadian dollar strengthens, the Canadian value of oil prices declines (Figure 9.3), and

2. the increase in the spread between light and heavy crude oil.

Figure 9.2 Marketable Natural Gas Volumes and Average Prices: 1982 - 1991

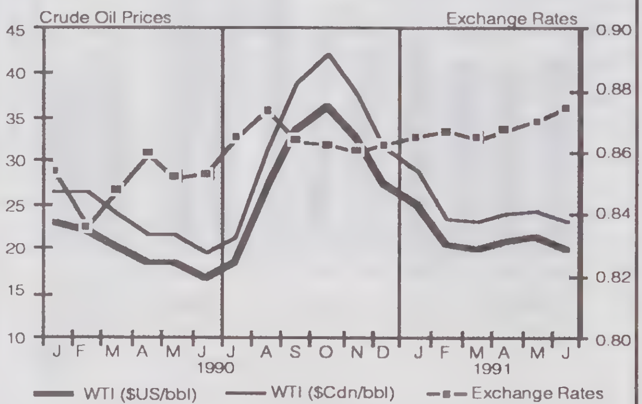


Note : The data for figures 9.1 and 9.2 are taken from the PMA's Monitoring Survey results except for the two end bars which are derived from Statistics Canada and EMR Oil and Gas Branch. The two data series are **not** entirely comparable since the PMA data shows prices to the producers, while the other data include transportation and gathering costs and are, therefore, higher than PMA numbers. The Monitoring Survey covers approximately 90% of the industry, compared with 100% for the other data series.

However, partly offsetting the downward pressure were gains made by oil and gas companies that, during the second half of 1990, sold crude oil into the futures market. These hedging activities resulted in significant incremental revenues for a number of producers. Gains in natural gas production were more than offset by lower prices, which declined to their lowest level in more than a decade. NGL sales were relatively strong in terms of both prices and volumes.

Sales revenues from refined petroleum products were also lower in the first half of 1991 as a result of a decline in overall Canadian demand. In addition, on January 1991 the Goods and Services Tax (GST) replaced the Federal Sales Tax (FST). The GST has been excluded from the companies' revenues and expenses in accordance with generally accepted accounting principles. By contrast, the FST was included in both revenues and expenses. Consequently, a discontinuity in revenue levels exists between the two periods.

Figure 9.3 Crude Oil Prices and Exchange Rates



	First Half 1990	First Half 1991
Avg. WTI ($US/bbl)	19.81	21.29
Avg. Exchange Rate	0.850	0.868
Avg. Cdn. Prices ($Cdn/bbl)	23.32	24.53

Sources: EMR, Oil and Gas Branch; Bank of Canada

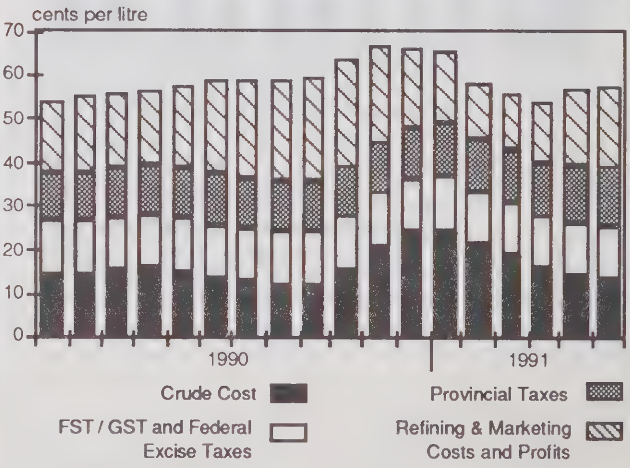
Table 9.1 Overview of Total Industry First Half

	1990	1991	Change	
	---- $ billions ----			(%)
Total Sales Revenue	20.9	20.7	-0.2	-1
Other Revenues	0.7	0.4	-0.3	-46
Total Expenses	20.4	21.2	0.8	4
All Current Taxes	0.6	0.3	-0.3	-53
Deferred Taxes	-	-0.1	-0.1	-
Net Income before Extraordinary Items	**0.5**	**-0.6**	**-1.1**	**-**
Extraordinary and Other Items	1.0	-	-1.0	-75
Net Income after Extraordinary Items	**0.6**	**-0.6**	**-1.2**	**-**
Internal Cash Flow	**3.1**	**2.5**	**-0.6**	**-19**

Internal cash flow declined 19% to $2.5 billion in the first half of 1991 due to higher expenses and lower operating and sales revenues. A $470 million decrease in total revenues together with an increase of $835 million (5%) in 'Other expenses' (which includes operating costs, cost of goods sold and royalty payments) caused the reduction in cash flow. Those factors more than offset a decrease in interest payments of 12% ($145 million). Current income taxes dropped 53% ($310 million) (Table 9.7).

In the downstream segment the flow through of high costs inventories in a period of falling prices (Figure 9.4) together with strong competition in domestic markets, significantly affected product margins and hence profitability.

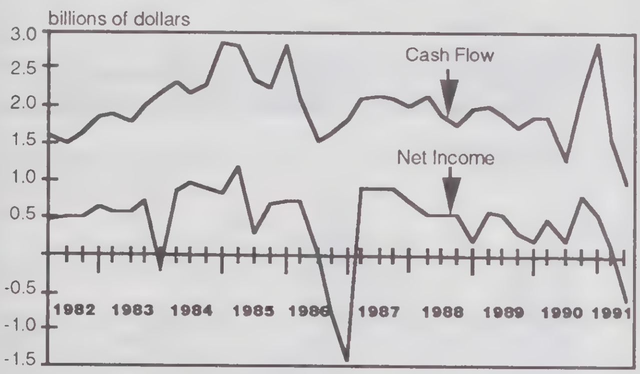
Figure 9.4 Average Retail Price of Motor Gasoline: Monthly, 1990 - 1991



Source: EMR, Oil and Gas Branch

Net income from all Canadian operations of the industry fell $1.2 billion from a profit of $615 million in the first half of 1990 to a loss of $565 million in the corresponding 1991 period. In addition to the factors affecting cash flow, the decline in net income was due to lower gains on sale of assets, down $275 million, larger write-offs, up $210 million, and higher depreciation, depletion and amortization, up $90 million.

Figure 9.5 Net Income and Cash Flow 1982 - 1991: Quarterly Data

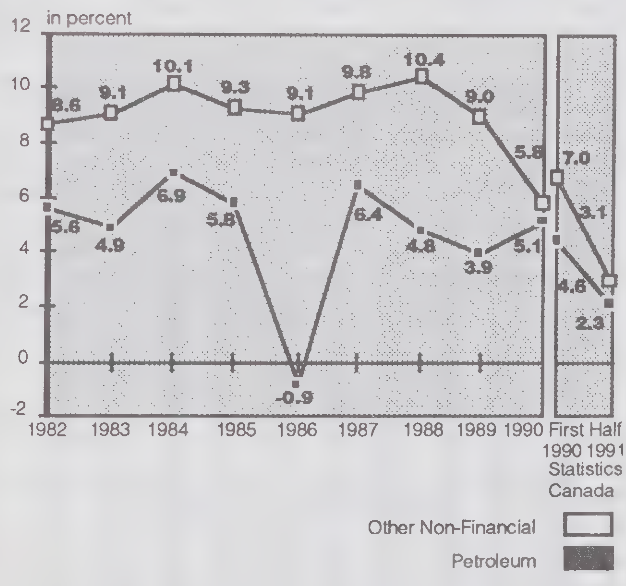


Canadian-controlled companies' cash flow decreased 9% ($110 million) to $1.2 billion in the first half of 1991 from $1.3 billion in the corresponding 1990 period. Lower sales revenues, down $200 million, or 3%, and a $110 million increase in 'Other expenses' (which includes operating and feedstock costs and royalties) contributed to reduce profits. Partly offsetting this decline were reduced interest charges, down $60 million, and current income taxes, down $150 million. Net income declined $260 million, from a profit of $85 million in the first half of 1990 to a loss of $175 million in the first half of 1991. Also affecting net income were higher deferred income taxes, up $110 million, and increased depreciation, depletion and amortization, up $70 million.

Foreign-controlled companies' cash flow fell 26% ($470 million) to $1.3 billion in the first half of 1991 from $1.8 billion in the corresponding 1990 period. Higher sales revenue of $35 million were more than offset by a $730 million rise in 'Other expenses' (includes operating and feedstock costs, and royalty payments). Moderating the decline in cash flow were lower current income taxes, down $160 million, and interest charges, down $80 million. Net income for this group fell $920 million. Apart from the factors affecting cash flow, the decline in net income was the result of lower gains on sale of assets, down $350 million, higher write-offs, up $195 million, and higher E&D expenses, up $40 million. Deferred tax recoveries of $220 million in 1991 vs. $45 million in 1990 partly offsetted the decrease in net income.

The petroleum industry's annualized **rate of return on capital employed** for the first half of 1991 was 2.3% vs. 4.6% for the corresponding 1990 period. The other non-financial industries (excluding petroleum) recorded a rate of return on capital employed of 3.1% for the first half of 1991, vs. 7% for the first half of 1990 (Figure 9.5 and Note).

Figure 9.6 Rates of Return on Capital Employed



Note : The data presented in this report for other non-financial industries are slightly different from those presented in previous reports due to a number of changes introduced by Statistics Canada to their statistical series beginning with the fourth quarter of 1990.

Dividend payments by the petroleum industry increased 8% to $675 million in the first half of 1991 from $625 million in the corresponding 1990 period. Dividends paid by Canadian-controlled companies increased 9% to $235 million, while dividend payments by foreign-controlled companies rose 8% to $440 million.

Table 9.2 Dividend Payments

	First Half 1990	First Half 1991	Per Cent of Net Income[a] 1990	Per Cent of Net Income[a] 1991
	- -$ millions - -		(%)	
Canadian-Controlled	213	232	253	n/a
Foreign-Controlled	410	442	77	n/a
Total Industry	623	674	101	n/a

(a) Percentages are derived by dividing dividend payments by net income.

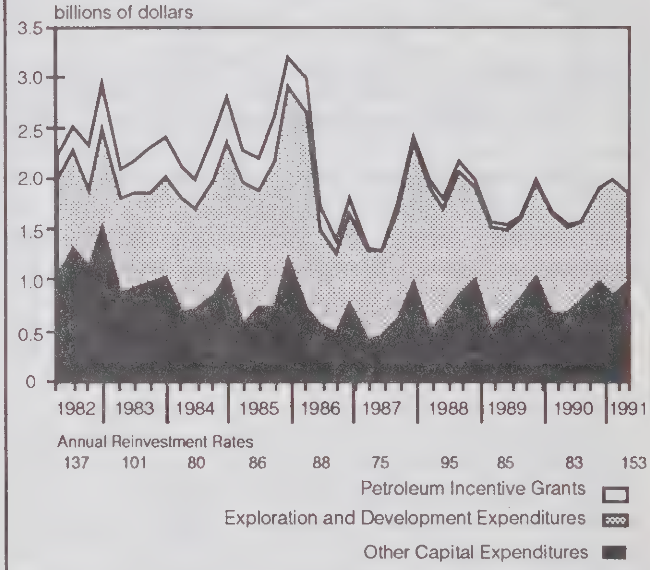
Overall gross capital expenditures for the petroleum industry increased 21% ($675 million) to $3.9 billion in the first half of 1991. Net of grants and incentives, capital expenditures rose 21% to $3.8 billion. The substantial rise is the result of increased capital investment in major projects, such as the Caroline gas field development, the Bi-Provincial heavy oil upgrader and the Hibernia project.

Table 9.3 Capital Expenditures and Reinvestment Rates

	First Half 1990	First Half 1991	Change	
	--- $	billions ---		(%)
Gross Capital Expenditures	3.2	3.9	0.3	21
Less: Incentive Grants	0.02	0.03	0.01	60
Net Capital Expenditures	3.2	3.8	0.3	21
Reinvestment Rate: Net Capital Expenditures as a Per Cent of Cash Flow	102%	153%		

Exploration and development spending rose 10% to $2 billion in the first half of 1991, while other capital expenditures including new constructions, buildings, machinery and equipments, increased 37% to $1.8 billion. Gross capital outlays for Canadian-controlled companies rose 9% to $1.7 billion, while those of foreign-controlled companies increased 33% to $2.2 billion (Table 9.5).

Figure 9.7 Capital Expenditures and Reinvestment Rates: 1982 - 1991



The total reinvestment rate increased to 153% in the first half of 1991 from 102% in the corresponding 1990 period (Table 9.4). The reinvestment rate for Integrateds and Refiners increased to 172% from 89%, while that of the Oil and Gas Producers group rose to 145% from 112%.

Table 9.4 Total Capital Expenditures (Net Of Incentive Grants) as a Per Cent of Internal Cash Flow
First Half

	1990	1991
	(%)	
Integrateds and Refiners	89	172
Canadian-Controlled	141	636
Foreign-Controlled	76	142
Senior Oil and Gas Producers	101	156
Canadian-Controlled	103	123
Foreign-Controlled	100	209
Junior Oil and Gas Producers	135	128
Canadian-Controlled	135	123
Foreign-Controlled	136	143
Oil and Gas Producers	112	145
Canadian-Controlled	116	123
Foreign-Controlled	108	187
Total Industry	**102**	**153**
Canadian-Controlled	121	143
Foreign-Controlled	90	160

Debt to Equity Analysis:[1]

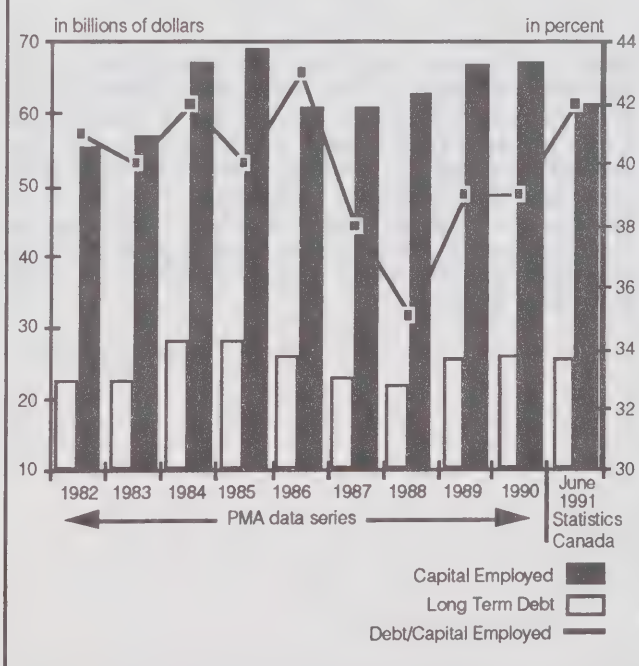
In the first half of 1991 the industry's long-term debt increased 7% ($1.8 billion) to $26 billion from $24.2 billion at the end of 1990. Canadian-controlled companies' debt rose 12% ($1.2 billion) mainly as the result of one company borrowing long-term and investing the proceeds in short-term fixed-income investments. Also, long-term debt rose following financial and operational reorganizations, and the spin-off of a petroleum company which assumed the long-term debt previously held by the parent company. In addition, redemptions of preferred shares were financed through short-term borrowings thereby reducing equity. The foreign-controlled group increased their debt by 4% ($580 million) mainly to fund higher spending on major capital projects (Table 9.9).

During the same period total shareholders' equity declined by 6% ($2.2 billion) to $35.4 billion. The decline was mainly attributable to the Canadian-controlled group of companies, and was the result of restructuring activity by a number of companies as contributed surplus and preferred shares were converted to common share capital and short-term liabilities.

As a result of the above changes in debt and equity, the ratio of debt to capital employed (defined as long-term debt, other long-term liabilities and total equity) increased to 42% from 39% at the end of 1990 (Figure 9.8).

(1) Debt includes long-term debt and other long-term liabilities.

Figure 9.8 Long-Term Debt to Capital Employed



Second Quarter 1991:

Net Income for the second quarter of 1991 declined $755 million to a loss of $615 million from a profit of $140 million for the corresponding 1990 period. The decrease in net income was primarily due to lower sales revenues, higher write-offs (up $200 million), and lower gains on sale of assets (down $205 million). 'Other expenses' (including operating costs, feedstock costs and royalty payments) increased only marginally, i.e. $70 million or less than 1%. Partly offsetting the lower revenues and higher write-offs were lower interest charges (down $90 million or 15%), a decline in current income taxes (down $150 million) and higher deferred tax recoveries (up $55 million). Internal cash flow decreased 23% to $965 million.

Overall capital expenditures in the second quarter of 1991 rose 22% to $1.9 billion. Exploration and development spending rose 5% to $890 million and other capital expenditures increased 43% to $990 million. The increase in the latter category is attributable to the acquisition of new buildings, machinery and equipment for major projects.

Note : This report was prepared on the basis of the quarterly data obtained from individual companies by the PMA via Statistics Canada. In contrast to the bi-annual PMA survey presentation, the report covers the combined results of upstream, downstream and other Canadian operations but excludes the results of Canadian companies' foreign activities. Nonetheless, the information contained in this analysis gives a reliable overview of the industry's financial performance for the first half of 1991.

September 1991

Table 9.5

Capital Expenditures of Petroleum Industry
First Half

	Total Industry 1990	Total Industry 1991	Total Industry Change %	Canadian-Controlled 1990	Canadian-Controlled 1991	Canadian-Controlled Change %	Foreign-Controlled 1990	Foreign-Controlled 1991	Foreign-Controlled Change %
	$ millions			$ millions			$ millions		
Exploration and Development									
E&D Expensed									
Land & Lease Acquisition and Retention	42	43	2	5	5	3	37	38	2
Drilling Expenditures	171	232	36	103	91	-12	69	140	103
Geological and Geophysical	181	138	-24	22	11	-50	159	127	-20
Total E&D Expensed	394	413	5	130	107	-18	265	305	15
E&D Capitalized									
Land & Lease Acquisition and Retention	334	320	-4	163	117	-28	171	203	19
Drilling Expenditures	963	1105	15	580	630	9	382	475	24
Geological and Geophysical	161	195	21	108	118	9	52	77	48
Total E&D Capitalized	1458	1620	11	851	865	2	605	755	25
Total Exploration and Development	**1852**	**2033**	**10**	**981**	**972**	**-1**	**870**	**1060**	**22**
Other Capitalized Expenditures									
Mining	39	30	-23	21	14	-36	18	17	-7
New Const., Build., Mach., and Equip.	1134	1619	43	510	652	28	624	967	55
Used Build., Mach., Equip., & Land	78	79	1	13	10	-23	65	69	6
Other Capital Expenditures	90	108	20	32	44	38	58	63	9
Total Other Capital Expenditures	1341	1836	37	576	720	25	765	1116	46
Total Capital Expenditures	**3193**	**3869**	**21**	**1557**	**1692**	**9**	**1635**	**2176**	**33**
Capital Grants	20	32	60	11	16	45	9	16	78
Net Capital Expenditures	**3173**	**3837**	**21**	**1546**	**1676**	**8**	**1626**	**2160**	**33**

Table 9.6

**Capital Expenditures of Petroleum Industry
Second Quarter**

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1990	1991	Change %	1990	1991	Change %	1990	1991	Change %
	$ millions			$ millions			$ millions		
Exploration and Development									
E&D Expensed									
Land & Lease Acquisition and Retention	15	21	38	3	1	-46	12	19	55
Drilling Expenditures	79	114	44	52	37	-29	28	76	171
Geological and Geophysical	75	47	-37	11	3	-73	64	43	-32
Total E&D Expensed	169	182	8	66	41	-38	104	138	33
E&D Capitalized									
Land & Lease Acquisition and Retention	172	189	10	79	53	-33	92	136	48
Drilling Expenditures	429	430	-	264	260	-2	165	170	3
Geological and Geophysical	74	88	19	51	47	-8	22	41	86
Total E&D Capitalized	675	707	5	394	360	-9	279	347	24
Total Exploration and Development	**844**	**889**	**5**	**460**	**401**	**-13**	**383**	**485**	**27**
Other Capitalized Expenditures									
Mining	20	9	-55	11	1	-86	9	7	-21
New Const., Build., Mach., and Equip.	571	867	52	254	293	15	317	574	81
Used Build., Mach., Equip., & Land	51	59	16	8	3	-63	43	56	29
Other Capital Expenditures	50	55	10	18	24	33	31	32	3
Total Other Capital Expenditures	692	990	43	291	321	11	400	669	67
Total Capital Expenditures	**1536**	**1879**	**22**	**751**	**722**	**-4**	**783**	**1154**	**47**
Capital Grants	12	16	33	7	8	14	5	8	60
Net Capital Expenditures	**1524**	**1863**	**22**	**744**	**714**	**-4**	**778**	**1146**	**47**

Table 9.7

Income Statement
First Half

	Total Industry 1990	Total Industry 1991	Total Industry Change %	Canadian-Controlled 1990	Canadian-Controlled 1991	Canadian-Controlled Change %	Foreign-Controlled 1990	Foreign-Controlled 1991	Foreign-Controlled Change %
	$ millions			$ millions			$ millions		
Sales Revenues	**20882**	**20718**	**-1**	**6952**	**6755**	**-3**	**13930**	**13963**	**-**
Other Revenues									
Interest from Canadian Sources	208	166	-20	98	75	-24	110	91	-17
Dividends from Canadian Corporations	28	38	34	21	20	-6	7	18	-
Foreign Dividends and Interest Revenues	6	7	16	-	1	96	6	6	-
Gains on Sale of Assets	431	157	-64	46	119	-	385	38	-90
Total Revenues	**21555**	**21085**	**-2**	**7117**	**6968**	**-2**	**14438**	**14116**	**-2**
Expenses									
E & D Expensed	406	425	5	130	108	-17	275	317	15
D, D & A Charges	2561	2653	4	1058	1126	6	1503	1527	2
Other Expenses	16264	17101	5	5150	5257	2	11114	11844	7
Interest Expenses	1178	1034	-12	524	462	-12	654	572	-12
Total Operating Expenses	**20408**	**21214**	**4**	**6863**	**6953**	**1**	**13546**	**14261**	**5**
Other Transactions									
Gains on Translation of Currency	71	31	-57	5	-19	-	66	49	-26
Write-offs and Valuation Adjustments	-133	-343	-	-91	-104	-	-42	-239	-
Income before Income Taxes	**1085**	**-441**	**-**	**169**	**-106**	**-**	**916**	**-335**	**-**
Income Taxes									
Current	585	277	-53	114	-36	-	471	313	-34
Deferred (tax allocation method)	-18	-130	-	27	134	-	-45	-264	-
Net Income after Income taxes	**516**	**-588**	**-**	**26**	**-204**	**-**	**491**	**-385**	**-**
Other Income									
Equity Income	100	25	-75	59	30	-49	41	-10	-
Extraordinary Items	-	-	-	-	-	-	-	-	-
Net Income after Extraordinary Items	**616**	**-563**	**-**	**84**	**-174**	**-**	**532**	**-389**	**-**
Cash Flow	**3096**	**2516**	**-19**	**1280**	**1168**	**-9**	**1815**	**1348**	**-26**

	Integrateds and Refiners 1990	Integrateds and Refiners 1991	Integrateds and Refiners Change %	Oil and Gas Producers 1990	Oil and Gas Producers 1991	Oil and Gas Producers Change %
	$ millions			$ millions		
Sales Revenues	**13790**	**13100**	**-5**	**7092**	**7618**	**7**
Other Revenues						
Interest from Canadian Sources	97	62	-36	111	103	-7
Dividends from Canadian Corporations	4	9	-	24	29	21
Foreign Dividends and Interest Revenues	-	-	-	6	7	15
Gains on Sale of Assets	429	63	-85	2	94	-
Total Revenues	**14320**	**13234**	**-8**	**7235**	**7851**	**9**
Expenses						
E & D Expensed	118	146	24	288	279	-3
D, D & A Charges	1063	1083	2	1499	1570	14
Other Expenses	11789	12004	2	4475	5098	11
Interest Expenses	529	440	-17	649	595	-8
Total Operating Expenses	**13498**	**13672**	**1**	**6910**	**7542**	**9**
Other Transactions						
Gains on Translation of Currency	12	11	-11	60	20	-66
Write-offs and Valuation Adjustments	-31	-166	-	-102	-177	-
Income before Income Taxes	**802**	**-593**	**-**	**283**	**152**	**-46**
Income Taxes						
Current	281	-96	-	304	374	23
Deferred (tax allocation method)	36	-49	-	-55	-81	-
Net Income after Income taxes	**485**	**-447**	**-**	**32**	**-141**	**-**
Other Income						
Equity Income	24	16	-34	75	9	-88
Extraordinary Items	-	-	-	-	-	-
Net Income after Extraordinary Items	**509**	**-431**	**-**	**107**	**-132**	**-**
Cash Flow	**1293**	**825**	**-36**	**1803**	**1691**	**-6**

Table 9.8

Income Statement
Second Quarter

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1990	1991	Change %	1990	1991	Change %	1990	1991	Change %
	$ millions			$ millions			$ millions		
Sales Revenues	**10194**	**9768**	**-4**	**3399**	**3115**	**-8**	**6795**	**6654**	**-2**
Other Revenues									
Interest from Canadian Sources	106	80	-25	58	37	-35	49	43	-12
Dividends from Canadian Corporations	15	12	-19	11	7	-35	4	5	31
Foreign Dividends and Interest Revenues	3	3	-18	-	1	48	3	2	-32
Gains on Sale of Assets	303	96	-68	33	114	-	271	-18	-
Total Revenues	**10622**	**9959**	**-**	**3500**	**3273**	**-7**	**7121**	**6685**	**-6**
Expenses									
E & D Expensed	175	186	6	66	42	-36	109	144	32
D, D & A Charges	1251	1275	2	511	559	9	740	716	-3
Other Expenses	8335	8404	1	2653	2478	-7	5682	5927	4
Interest Expenses	601	511	-15	276	232	-16	325	279	-14
Total Operating Expenses	**10362**	**10376**	**-**	**3507**	**3311**	**-**	**6855**	**7065**	**3**
Other Transactions									
Gains on Translation of Currency	46	31	-33	6	-	-96	40	30	-24
Write-offs and Valuation Adjustments	-111	-312	-	-88	-102	-	-23	-211	-
Income before Income Taxes	**195**	**-700**	**-**	**-89**	**-139**	**-**	**283**	**-560**	**-**
Income Taxes									
Current	133	-15	-	35	-37	-	98	22	-77
Deferred (tax allocation method)	-12	-66	-	-41	75	-	29	-141	-
Net Income after Income taxes	**73**	**-618**	**-**	**-83**	**-177**	**-**	**156**	**-442**	**-**
Other Income									
Equity Income	64	3	-95	17	-3	-	47	6	-87
Extraordinary Items	-	-	-	-	-	-	-	-	-
Net Income after Extraordinary Items	**138**	**-616**	**-**	**-67**	**-180**	**-**	**204**	**-437**	**-**
Cash Flow	**1249**	**963**	**-23**	**503**	**488**	**-3**	**746**	**475**	**-36**

	Integrateds and Refiners			Oil and Gas Producers		
	1990	1991	Change %	1990	1991	Change %
	$ millions			$ millions		
Sales Revenues	**6990**	**6245**	**-11**	**3205**	**3523**	**10**
Other Revenues						
Interest from Canadian Sources	49	23	-53	57	57	-1
Dividends from Canadian Corporations	2	3	85	13	8	-34
Foreign Dividends and Interest Revenues	-	-	-	3	3	-17
Gains on Sale of Assets	308	1	-100	-5	95	-
Total Revenues	**7348**	**6272**	**-15**	**3274**	**3687**	**13**
Expenses						
E & D Expensed	60	67	13	116	119	3
D, D & A Charges	524	513	-2	727	762	5
Other Expenses	6142	5935	-3	2193	2469	13
Interest Expenses	274	208	-24	327	302	-8
Total Operating Expenses	**6999**	**6724**	**-4**	**3362**	**3652**	**9**
Other Transactions						
Gains on Translation of Currency	12	5	-54	34	25	-25
Write-offs and Valuation Adjustments	-18	-170	-	-93	-143	-
Income before Income Taxes	**342**	**-617**	**-**	**-148**	**-83**	**-**
Income Taxes						
Current	119	-86	-	14	71	-
Deferred (tax allocation method)	-10	-93	-	-2	27	-
Net Income after Income taxes	**233**	**-438**	**-**	**-160**	**-181**	**-**
Other Income						
Equity Income	12	-	-	52	3	-94
Extraordinary Items	-	-	-	-	-	-
Net Income after Extraordinary Items	**246**	**-438**	**-**	**-108**	**-178**	**-**
Cash Flow	**506**	**214**	**-58**	**744**	**749**	**1**

Table 9.9

Balance Sheet

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	Dec. 31 1990	Jun. 30 1991	Change %	Dec. 31 1990	Jun. 30 1991	Change %	Dec. 31 1990	Jun. 30 1991	Change %
	$ millions			$ millions			$ millions		
Cash, Investments and Marketable Securities	819	554	-32	337	306	-9	482	249	-48
Accounts Receivable:									
Trade (include affiliates)	6530	5053	-23	2248	1730	-23	4282	3323	-22
All Other	465	823	77	309	354	15	155	468	202
Total	6995	5875	-16	2557	2084	-18	4438	3791	-15
Inventories	5457	4008	-27	1583	1206	-24	3874	2803	-28
Other Current Assets	824	2496	-	326	1364	-	498	1131	127
Total Current Assets	**14095**	**12933**	**-8**	**4803**	**4960**	**3**	**9292**	**7974**	**-14**
Net Fixed and Depletable Assets	62007	61677	-1	25742	25696	-	36265	35982	-1
Other Long-term Assets	8193	7675	-6	4540	4144	-9	3653	3529	-3
Total Assets	**84295**	**82285**	**-2**	**35085**	**34800**	**-1**	**49210**	**47485**	**-4**
Accounts payable:									
Trade (include affiliates)	5534	4279	-23	2362	1715	-27	3173	2564	-19
All Other	1602	2092	31	304	483	59	1298	1608	24
Total	7137	6370	-11	2666	2198	-18	4471	4172	-7
Other Current Liabilities	4332	3727	-14	1822	2044	12	2510	1683	-33
Total Current Liabilities	**11469**	**10097**	**-12**	**4488**	**4242**	**-6**	**6981**	**5855**	**-16**
Long-term Debt	21924	23075	5	8813	9474	7	13111	13602	4
Accumulated Deferred Income Taxes	10963	10777	-2	4319	4436	3	6645	6342	-5
Other Long-term Liabilities	2296	2898	26	802	1316	64	1492	1579	6
Sareholders' Equity									
Common	14153	14455	2	7584	7720	2	6569	6735	3
Preferred	3399	2775	-18	1992	1495	-25	1408	1280	-9
Retained earnings	15142	13905	-8	3681	3274	-11	11461	10632	-7
Contributed surplus	4949	4303	-13	3406	2843	-17	1543	1460	-5
Total Liabilities, Deferred Taxes and Equity	**84295**	**82285**	**-2**	**35085**	**34800**	**-1**	**49210**	**47485**	**-4**
Working Capital	**2626**	**2836**	**8**	**315**	**718**	**128**	**2311**	**2119**	**8**

	Integrateds and Refiners			Oil and Gas Producers		
	Dec. 31 1990	Jun. 30 1991	Change %	Dec. 31 1990	Jun. 30 1991	Change %
	$ millions			$ millions		
Cash, Investments and Marketable Securities	149	97	-35	669	458	-32
Accounts Receivable:						
Trade (include affiliates)	3970	3022	-24	2560	2031	-21
All Other	152	517	241	313	306	-2
Total	4122	3538	-14	2873	2337	-19
Inventories	4821	3422	-29	636	586	-8
Other Current Assets	237	717	202	588	1779	203
Total Current Assets	**9329**	**7774**	**-17**	**4766**	**5160**	**8**
Net Fixed and Depletable Assets	27817	27644	-1	34191	34034	-
Other Long-term Assets	2472	2266	-8	5720	5407	-5
Total Assets	**39618**	**37684**	**-5**	**44677**	**44601**	**-**
Accounts payable:						
Trade (include affiliates)	3238	2554	-21	2297	1725	-25
All Other	1022	1211	18	580	881	52
Total	4260	3765	-12	2877	2605	-9
Other Current Liabilities	2790	1715	-39	1541	2012	31
Total Current Liabilities	**7050**	**5480**	**-22**	**4418**	**4617**	**5**
Long-term Debt	8454	8456	-	13470	14619	9
Accumulated Deferred Income Taxes	5514	5418	-2	5449	5360	-2
Other Long-term Liabilities	730	1136	56	1569	1760	12
Sareholders' Equity						
Common	5066	5312	5	9086	9143	1
Preferred	15	15	-1	3384	2760	-18
Retained earnings	9734	8957	-8	5407	4948	-8
Contributed surplus	3055	2910	-5	1894	1394	-26
Total Liabilities, Deferred Taxes and Equity	**39618**	**37684**	**-5**	**44677**	**44601**	**-**
Working Capital	**2279**	**2294**	**1**	**348**	**543**	**56**

Appendix I
Production of Canadian Crude Oil and Equivalent

		1990					1991	
		1Q	2Q	3Q	4Q	Year	1Q	2Q
		(000 m³/d)						
A.	**Light and Equivalent**							
	Alberta	120.9	113.0	116.7	116.6	116.8	117.2	114.2
	B.C.	5.6	5.0	5.1	5.4	5.3	5.7	5.4
	Saskatchewan	10.9	10.8	12.4	12.4	11.7	11.8	11.0
	Manitoba	2.0	2.0	2.0	2.0	2.0	2.0	1.9
	Ontario	0.7	0.7	0.6	0.6	0.6	0.6	0.7
	Other	5.1	5.0	4.9	5.2	5.0	5.3	5.2
	Total	**145.2**	**136.5**	**141.7**	**142.2**	**141.4**	**139.6**	**138.4**
	Synthetic							
	Suncor	9.2	5.0	8.3	10.3	8.2	9.9	9.8
	Syncrude	15.9	28.9	26.6	27.2	24.6	25.2	22.5
	Total	**25.1**	**33.9**	**34.9**	**37.5**	**32.8**	**35.1**	**32.3**
	Pentanes Plus*	**5.8**	**6.9**	**6.4**	**6.7**	**6.4**	**6.9**	**6.3**
	Total Light	**176.1**	**177.3**	**183.0**	**186.4**	**180.6**	**184.5**	**177.0**
B.	**Heavy Crude Alberta**							
	Conventional	28.0	27.8	28.3	29.0	28.3	28.8	27.6
	Bitumen	21.4	19.4	22 3	22.9	21.5	21.1	17.7
	Diluent	10.0	7.8	8.7	10.0	9.1	9.9	7.6
	Total	**59.4**	**55.0**	**59.3**	**61.9**	**58.9**	**59.8**	**52.9**
	Saskatchewan							
	Conventional	21.5	21.7	21.1	21.5	21.5	22.1	21.1
	Diluent	3.0	2.8	2.5	2.8	2.8	3.4	2.7
	Total	**24.5**	**24.5**	**23.6**	**24.3**	**24.3**	**25.5**	**23.8**
	Total Heavy	**83.9**	**79.5**	**82.9**	**86.2**	**83.2**	**85.3**	**76.7**
C.	**Production**	**260.0**	**256.8**	**265.9**	**272.6**	**263.8**	**269.8**	**253.7**

* *excludes diluent*

Appendix II
Supply and Disposition of Canadian Crude Oil and Equivalent

		1990					1991	
		1Q	2Q	3Q	4Q	Year	1Q	2Q
		(000 m³/d)						
A.	**Light and Equivalent**							
	Supply							
	Production	176.1	177.3	183.0	186.4	180.7	184.6	177.1
	Newgrade	0.5	1.1	1.4	2.4	1.4	1.6	1.0
	Draw/(Build)	5.1	-0.3	6.7	3.5	3.8	4.1	8.8
	Net Supply	181.7	178.1	191.1	192.3	185.9	190.3	186.9
	Domestic Demand							
	Atlantic	0	0	0	0	0	0	0
	Quebec	7.1	11.4	9.7	4.1	8.1	4.9	3.2
	Ontario	67.6	55.4	65.8	70.0	64.7	56.6	56.2
	Prairies	53.7	46.0	49.4	51.6	50.2	45.1	46.0
	B.C.	17.7	17.4	18.8	18.5	18.1	18.1	16.5
	Total	**146.0**	**130.2**	**143.7**	**144.3**	**141.1**	**124.7**	**121.9**
	Exports	35.6	48.0	47.4	48.0	44.8	65.6	65.0
	Total Demand	**181.6**	**178.2**	**191.1**	**192.3**	**185.9**	**190.3**	**186.9**
B.	**Heavy Crude (Blended)**							
	Supply							
	Production	83.9	79.4	82.9	86.2	83.2	85.2	76.7
	Recycled Diluent	0.5	1.3	1.5	0.8	1.0	0.7	1.2
	Draw/(Build)	(1.8)	0.2	1.8	(2.7)	(0.7)	(1.1)	0.4
	Net Supply	82.6	80.9	86.2	84.3	83.5	84.8	78.3
	Domestic Demand							
	Atlantic	0	0.4	0.9	0.2	0.4	0	0
	Quebec	5.1	4.9	4.1	1.2	3.8	0	0
	Ontario	8.9	7.0	8.4	10.2	8.7	9.1	11.4
	Prairies	7.3	11.1	14.6	10.4	10.8	9.1	6.7
	B.C.	0.2	0.3	0.4	0.8	0.4	0.5	0.5
	Total	**21.6**	**23.6**	**28.4**	**22.8**	**24.1**	**18.8**	**18.7**
	Exports	**61.1**	**57.3**	**57.8**	**61.4**	**59.4**	**66.1**	**59.6**
	Total Demand	**82.7**	**80.9**	**86.2**	**84.2**	**83.5**	**84.9**	**78.3**

Appendix III
Crude Oil Exports by Destination

U.S. PAD* Districts		1990 1Q	1990 2Q	1990 3Q	1990 4Q	1990 Year	1991 1Q	1991 2Qe)
		(000 m³/d)						
PADD I	Light	6.3	7.8	7.8	7.0	7.3	6.5	5.5
	Heavy	1.8	1.1	1.2	1.2	1.3	1.7	1.2
	Total	**8.1**	**8.9**	**9.0**	**8.2**	**8.6**	**8.2**	6.7
PADD II	Light	19.0	29.2	28.4	31.2	27.0	47.2	46.0
	Heavy	50.5	50.3	52.5	54.2	51.9	55.5	54.8
	Total	**69.5**	**79.5**	**80.9**	**85.4**	**78.9**	**102.7**	**100.8**
PADD III	Light	0	0	0	0	0	0	0
	Heavy	3.3	1.4	0	0.6	1.3	3.1	0
	Total	**3.3**	**1.4**	**0**	**0.6**	**1.3**	**3.1**	**0**
PADD IV	Light	9.0	9.5	10.5	8.8	9.4	9.4	10.7
	Heavy	2.3	2.9	3.4	3.4	3.0	2.9	1.7
	Total	**11.3**	**12.4**	**13.9**	**12.2**	**12.4**	**12.3**	**12.4**
PADD V	Light	0.7	1.3	0.8	0.4	0.7	1.3	1.6
	Heavy	0.8	0.8	0.8	1.1	0.9	0.4	0.8
	Total	**1.5**	**2.1**	**1.6**	**1 5**	**1.6**	**1.7**	**2.4**
U.S.	Light	35.0	47.8	47.5	47.4	44.4	64.4	63.8
	Heavy	58.7	56.5	57.9	60.5	58.4	63.6	58.5
	Total	93.7	104.3	105.4	107.9	102.8	128.0	122.3
Offshore	Light	0.4	0	0	0	0.1	0.8	1.2
	Heavy	2.5	0.8	0	1 6	1 2	2.3	1.1
	Total	2.9	0.8	0.0	1.6	1.3	3.1	2.3
Total	Light	35.4	47.8	47.5	47.4	44.5	65.2	65.0
	Heavy	61.2	57.3	57.9	62.1	59.6	65.9	59.6
	Total	96.6	105.1	105.4	109.5	104.1	131.1	124.6

** U.S. Petroleum Administration for Defense (PAD) Districts*

Appendix IV
Pipeline Deliveries

		1990					1991	
		1Q	2Q	3Q	4Q	Year	1Q	2Q
		(000 m³/d)						
A.	**Trans Mountain Pipe Line (TMPL)**							
	Domestic Deliveries							
	Light Crude	13.5	14.4	15.4	14.9	14.6	14.5	14.2
	Heavy Crude	0.2	0.3	0.3	0.3	0.3	0.4	0.2
	Semi Refined Poducts	5.1	5.0	5.6	5.3	5.3	5.5	3.7
	Refined Products	2.7	2.6	2.6	2.7	2.6	2.4	2.0
	Total	**21.5**	**22.3**	**23.9**	**23.3**	**22.8**	**22.8**	**20.1**
	Foreign Deliveries							
	Tankers	4.4	1.6	1.1	4.7	3.0	5.7	2.2
	Puget Sound Area	0.7	1.3	0.5	0.7	0.8	1.1	1.4
	Total	**5.1**	**2.9**	**1.6**	**5.4**	**3.8**	**6.8**	3.6
	Total TMPL	**26.6**	**25.2**	**25.5**	**28.7**	**26.6**	**29.6**	**23.7**
B.	**Interprovincial Pipe Line (IPL)**							
	Domestic Deliveries							
	Light Crude	88.1	76.2	86.4	85.0	84.1	74.2	74.6
	Heavy Crude	19.7	17.5	17.9	14.4	17.4	12.3	12.3
	Other(1)	32.8	30.0	25.3	30.1	29.7	28.6	26.5
	Total	**140.6**	**124.2**	**129.6**	**129.5**	**131.2**	**115.1**	**113.4**
	Foreign Deliveries(2)							
	Light Crude	25.8	37.3	36.6	38.2	34.6	54.2	49.6
	Heavy Crude	52.3	51.4	53.9	55.1	53.2	57.6	55.3
	Other(1)	7.6	9.0	5.7	6.1	7.1	6.8	7.8
	Total	**85.7**	**97.7**	**96.2**	**99.4**	**94.9**	**118.6**	**112.7**
	Total IPL	**226.3**	**221.9**	**225.8**	**228.9**	**226.1**	**233.7**	**226.1**
C.	**Pipeline to Montreal**							
	IPL Deliveries							
	To Montreal	12.7	16.3	14.2	5.8	12.3	4.9	3.1
	For Export/Transfer	4.5	0.4	0.6	0	1.2	0	1.1
	Total IPL	**17.2**	**16.7**	**14.9**	**5.1**	**13.5**	**4.9**	**4.2**
	Portland-Montreal							
	Montreal Imports(3)	17.0	8.5	16.8	24.2	16.7	24.2	22.4
	Total Mtl Receipts	**29.7**	**24.8**	**31.0**	**30.0**	**29.0**	**29.1**	**25.5**

Note (1): includes petroleum products and NGL's.
(2): includes US domestic crudes delivered to the U.S.
(3): includes cargo imported directly into Montreal.

Appendix V
Canadian Refinery Receipts

	1990 1Q	1990 2Q	1990 3Q	1990 4Q	1990 Year	1991 1Q	1991 2Q
	(000 m³/d)						
A. Domestic Receipts							
Light & Equivalent							
Atlantic	0	0	0	0	0	0	0
Quebec	7.1	11.4	9.7	4.1	8.1	4.9	3.1
Ontario	67.5	55.3	65.8	70.0	64.7	56.6	56.2
Prairies	53.7	46.0	49.5	51.6	50.2	45.1	46.0
B.C.	17.6	17.4	18.9	18.5	18.1	18.1	16.5
Total	**145.9**	**130.1**	**143.9**	**144.2**	**141.1**	**124.7**	**121.8**
Heavy							
Atlantic	0	0.4	0.9	0.2	0.4	0	0
Quebec	5.2	4.9	4.2	1.2	3.9	0	0
Ontario	8.8	7.0	8.4	10.2	8.6	9.1	11.4
Prairies	7.4	11.1	14.5	10.4	10.9	9.0	6.7
B.C.	0.2	0.3	0.4	0.8	0.4	0.6	0.5
Total	**21.6**	**23.7**	**28.4**	**22.8**	**24.2**	**18.7**	**18.6**
Other Receipts*							
Atlantic	0.8	0.5	0.1	0	0.3	0	1.2
Quebec	1.4	1.1	0.4	0.5	0.9	0	0.2
Ontario	3.3	3.9	2.9	3.7	3.4	3.4	5.3
Prairies	3.4	2.6	2.9	3.7	3.2	3.6	6.1
B.C.	5.3	5.0	5.9	5.4	5.4	5.5	4.0
Total	**14.2**	**13.1**	**12.2**	**13.3**	**13.2**	**12.5**	**16.8**
Total Domestic Receipts							
Atlantic	0.8	0.9	1.0	0.2	0.7	0	1.2
Quebec	13.7	17.4	14.3	5.8	12.9	4.9	3.3
Ontario	79.6	66.2	77.1	83.9	76.7	69.1	72.9
Prairies	64.5	59.7	66.9	65.7	64.3	57.7	58.8
B.C.	23.1	22.7	25.2	24.7	23.9	24.2	21.0
Total	**181.7**	**166.9**	**184.5**	**180.3**	**178.5**	**155.9**	**157.2**
B. Crude Oil Imports							
Atlantic	50.2	47.3	48.3	47.7	48.4	50.7	37.6
Quebec	35.2	25.0	36.9	43.1	35.1	39.6	35.7
Ontario	5.1	2.6	2.1	1.5	2.8	0.6	0.4
Prairies	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	0	0
Total	**90.5**	**74.9**	**87.3**	**92.3**	**86.3**	**90.9**	**73.7**
C. Total Receipts*							
Atlantic	51.5	48.2	49.4	47.9	49.1	50.7	38.8
Quebec	48.9	42.4	51.2	48.9	48.0	44.5	39.0
Ontario	84.7	68.8	79.2	85.4	79.5	69.7	73.3
Prairies	64.5	59.7	66.9	65.7	64.3	57.7	58.8
B.C.	23.1	22.7	25.2	24.7	23.9	24.2	21.0
Total	**272.2**	**241.8**	**271.8**	**272.6**	**264.8**	**246.8**	**230.9**

* *Partially processed oil, gas plant butanes etc.*

Appendix VI
International and Domestic Crude Oil Prices
(US$/bbl)

A.

At Source		Canadian Par	WTI NYMEX	Brent
1990	1Q	21.17	21.71	19.81
	2Q	17.33	17.97	16.27
	3Q	25.34	26.28	26.44
	4Q	30.94	32.08	32.66
	Ave	23.73	24.49	23.87
1991	1Q	20.72	21.81	20.95
	2Q	19.73	20.77	18.94

B.

At Chicago		Canadian Par	WTI NYMEX	Brent
1990	1Q	22.34	22.31	21.63
	2Q	18.61	18.56	18.07
	3Q	26.66	26.88	28.27
	4Q	32.25	32.67	34.54
	Ave	25.00	25.09	25.70
1991	1Q	22.01	22.41	23.22
	2Q	21.01	21.37	20.93

C.

At Montreal		Canadian Par	Brent
1990	1Q	22.50	21.99
	2Q	18.85	17.86
	3Q	26.90	27.88
	4Q	32.48	34.41
	Ave	25.21	25.61
1991	1Q	22.29	22.88
	2Q	21.30	20.59

Appendix VII
Average Regular Unleaded Gasoline Prices
(Self-Serve)
1990-1991

	1990			1991	
	June 26	Sept 25	Dec 25	March 26	June 25
	cents per litre				
St John's (NFLD)	59.6	64.4	72.6	62.0	61.8
Charlottetown	57.7	58.5	68.4	65.6	60.3
Halifax*	57.5	56.3	70.6	61.7	60.3
Saint John (N.B.)*	55.9	60.1	67.3	57.7	57.7
Montreal	61.9	64.0	71.0	63.0	63.2
Toronto	53.9	59.3	58.8	54.8	57.5
Winnipeg	49.9	56.9	64.9	49.0	47.2
Regina	54.9	58.9	62.9	49.9	38.9
Calgary	53.3	55.7	60.0	42.0	47.6
Vancouver	59.9	64.9	56.6	55.4	53.2
Average	**56.8**	**60.8**	**64.6**	**55.6**	**54.7**
Consumption taxes inlcude:					
Federal	12.1	12.2	12.3	12.0	12.2
Provincial	11.4	11.3	11.4	11.6	13.1

* *Full-Serve*

Appendix VIII
Consumption Taxes on Petroleum Products
(June 1991)

	Ad valorem		Gasoline			Diesel
	Mogas	Diesel	Reg L	Mid UL	Prem UL	Diesel
	%		(cents per litre)			
Federal Taxes						
Estimated GST (7%)			3.6	3.8	4.0	3.5
Excise			8.50	8.5	8.5	4.0
Provincial Taxes						
Newfoundland [(a)]	23	27	13.7	13.7*	13.7*	15.6*
Prince Edward Island	23	26	12.3*	12.3*	12.3*	12.4*
Nova Scotia	24.5	31.5	12.4*	12.4*	12.4*	14.7*
New Brunswick	24.5	31.5	12.7*	12.2*	12.2*	13.7*
Quebec [(b)]			12.0*	12.0*	12.0*	10.6*
Ontario			13.0	13.0*	13.0*	12.6*
Manitoba			10.5*	10.5*	10.5*	10.9*
Saskatchewan			10.0	10.0	10.0	10.0
Alberta			9.0*	9.0*	9.0*	9.0*
British Columbia [(c)]	22.5	(d)	10.74*	10.74*	10.74*	11.18*
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	(e)	11.2	11.2	11.2*	9.5*

(a) The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay, Labrador.

(b) Reduced by varying amounts in certain remote areas and within 20 kilometres of the provincial and U.S. borders.

(c) Additional transit tax of 3.0 cents per litre in Vancouver.

(d) The tax on diesel 0.44 cents per litre higher than the unleaded tax.

(e) 85% of gasoline tax.

* *changed since last quarter*

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional area	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude Oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydro carbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Synthetic crude oil	Crude oil production treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

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The Canadian Oil Market

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Canadian Oil Markets and Emergency Planning Division
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The Canadian Oil Market

Overview

This issue of the Canadian Oil Market reviews Canadian oil supply and demand developments in 1991. Also included, for the first time in this publication, is a detailed table outlining Canadian refining capacity by region provided by the *Petroleum Technology Division*. This issue also contains a review of the financial performance of the Canadian oil and gas industry in 1991 prepared by the *Petroleum Monitoring and Information Services Division.*

Highlights

- Canada produced slightly less crude oil in 1991. This drop would have been higher had it not been for record levels of synthetic crude oil output.

- Sales of refined petroleum products continued to decline primarily as a result of the recession.

- A rise in crude oil imports into eastern Canada, reflected the mid-summer closure of the Sarnia-Montreal extension of the Interprovincial Pipe Line.

- Crude oil exports rose significantly in 1991 as a result of a large drop in domestic demand for indigenous crude oil feedstocks.

- Stocks of crude oil and petroleum products closed 1991 unchanged from the year before.

- After a post Gulf war drop in crude oil prices, prices firmed over the last several months of the year.

- By mid-1991 petroleum product prices had returned to pre-Gulf war levels after reaching their highest level in recent history early in the year.

- Net income from all Canadian oil and gas operations fell $3.9 billion, from a profit of $2.0 billion in 1990 to a loss of $1.9 billion in 1991.

The Canadian Oil Market

1. Refined Petroleum Product Demand

. *Domestic demand for refined products remained weak in 1991 despite the decline in prices following the Gulf war. Sales are not expected to recover until the economy is fully out of the recession.*

Sales of refined oil products in Canada fell by 6% in 1991, averaging 216 000 m^3/d, or some 15 000 m^3/d below the previous year. After demand plummeted by 11% year-over-year in the first quarter, the rate of decline subsequently moderated such that, by the fourth quarter, sales were down by only 3%. Trends in product sales were reflective of both a stalled economic recovery and intertemporal changes in refined product prices.

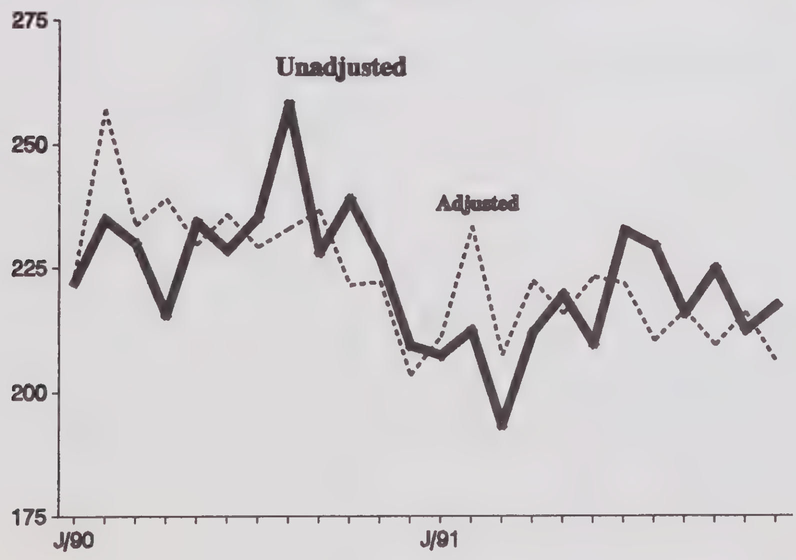
Economic growth remained essentially flat in 1991 after partially recovering from a significant drop in GDP (Gross Domestic Product) during the six-month period spanning the final quarter of 1990 and the first quarter of 1991. Moreover, the Gulf conflict caused product prices to escalate at about the same time as the economy was bottoming out, exacerbating the slump in demand.

Sales started to recover by the second quarter of 1991 in tandem with the modest upturn in the economy; and the gradual return of product prices to their pre-conflict levels. However, as in the case of the economy generally, the recovery in product demand has been weak and only partial, and perhaps will remain so until there is a marked improvement in the economy.

All the major refined products saw lower sales in 1991. Demand for motor gasoline declined 3% to 90 000 m^3/d while diesel fuel sales slipped by 5% to 44 000 m^3/d. Consumption of heating oil dropped by 10% to 18 000 m^3/d. Reduced demand in the electric power and industrial sectors of eastern Canada resulted in a 16% drop to 22 000 m^3/d in heavy fuel oil sales. Sales of 'other products' declined by 8% to 42 000 m^3/d, mainly because of lower demand for jet fuel, asphalt and petrochemical feedstocks.

The figure below compares actual with seasonally adjusted sales over the last two years.

Figure 1.1
Refined Petroleum Product Sales
000 m^3/d



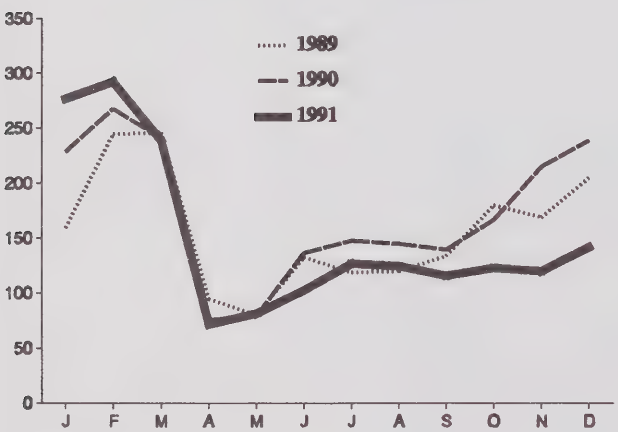
2. Drilling and Exploration Activity

. Overcapacity in the drilling industry continued through 1991 with only 3 out every 10 drilling rigs active. Activity is expected to fall further in 1992 with well completions down 22%.

1991 proved to be one of the worst years on record for the drilling industry in western Canada. Despite the introduction of Alberta's temporary crude oil royalty 'holiday' program; weak crude oil and natural gas prices, and severe industry cost-cutting measures pushed drilling activity down to its lowest level in decades.

According to the CAODC (Canadian Association of Oil Drilling Contractors), the drilling industry in western Canada has been in decline since 1985. The industry was expected to post a modest upturn in 1991 bolstered by demand for natural gas. With gas prices depressed, drilling activity fell short of expectations with only 31% of 469 available rigs reported active compared with 35% of 487 the year before.

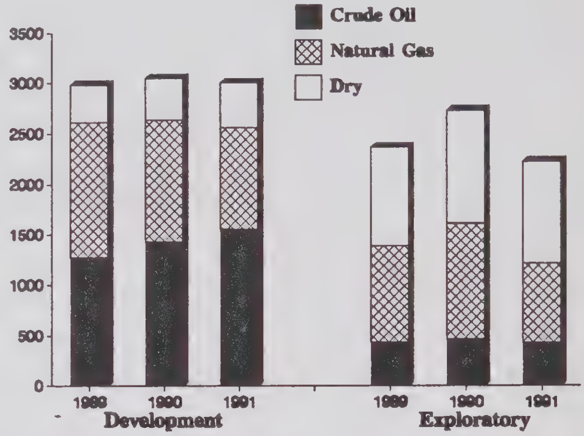
Figure 2.1
Drilling Activity in Western Canada
(Number of Active Rigs)



There were 9% less oil and natural gas wells completed in 1991 compared with the year before. By year-end, about 5230 wells (including nearly 30% dry) had been drilled, the lowest number of wells since 1975. Total metres drilled fell nearly 8% to 6.4 million.

Oil and gas exploration completions were down 18% to about 2230 wells with gas completions registering a sharp 30% drop. In fact, for the first time since 1985 declining oil exploration has not been offset by an increase in drilling for natural gas. Development well completions totalling 3000 remained relatively unchanged with a rise in oil completions in Alberta offsetting a fall in gas activity.

Figure 2.2
Well Completions
(Number of wells)



In November of 1991, the government of Alberta, in an attempt to stimulate oil drilling activity, temporarily suspended the collection of royalties on all types of new and reactivated oil wells. While the announcement was generally well received, some analysts considered the short-term break to be too little, too late. With drilling early in 1992 continuing to fall short of post announcement forecasts, calls are again being heard for more fundamental changes to the royalty system.

Drilling activity in 1992 could fall below that recorded in 1991. A poor winter drilling season, prompted the CAODC to adjust its 1992 drilling forecast downward. The association now expects only 23% of 424 available rigs to be operating over the year with about 4100 wells drilled compared with over 5000 in 1991. This would represent the fourth consecutive money-losing year for an industry which is said to require a 55% active rig utilization rate to break even.

3. Crude Oil Supply

. *Domestic heavy crude oil producers were particularly hard hit by the post Gulf war drop in crude oil prices and the international over supply of crude.*

. *As a result of the closure of the Sarnia-Montreal pipeline, Quebec became dependent on offshore crude for virtually all of its refinery feedstock requirements.*

3.1 Total Crude Oil Supply

Total crude oil supply in 1991 averaged 362 000 m^3/d compared with 350 000 m^3/d a year earlier. Of this volume domestic supply (including recycled diluent, production from Ontario, surplus Newgrade supply re-injected into the Interprovincial pipeline system and inventory change) averaged 270 000 m^3/d. Gross imports averaged 92 000 m^3/d.

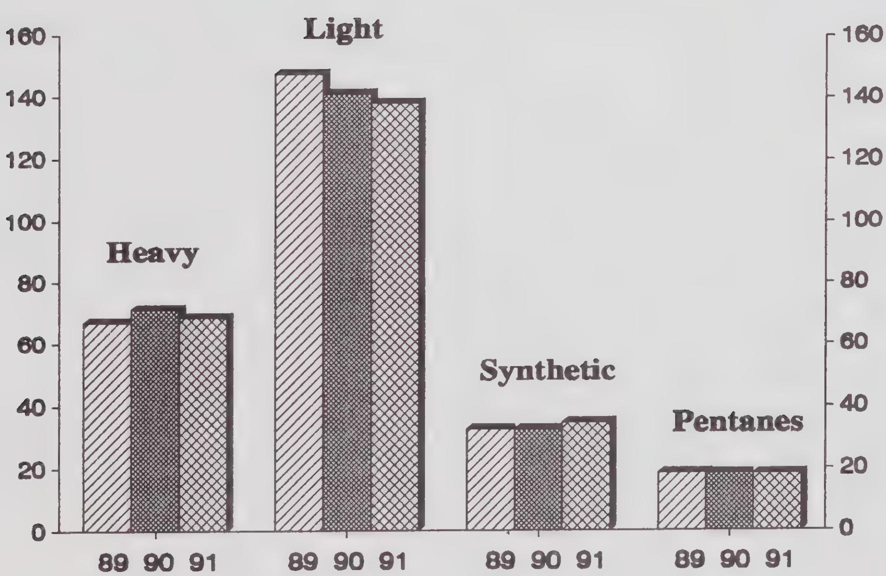
3.2 Domestic Production

Crude oil production in 1991 averaged 260 000 m^3/d, about 4 000 m^3/d below a year earlier. The drop would have been much higher had it not been for record levels of synthetic crude output (oilsands) offsetting declines in conventional light and heavy crude production.

Heavy crude producers were particularly affected by the post Gulf war drop in crude oil prices and world surplus of heavy crude oil. A wide price differential particularily early in the year between cheaper heavy, sour crudes and light, sweet grades resulted in the shut in of some expensive heavy crude oil (bitumen) production.

The oversupply situation was further exacerbated by reduced domestic demand as a result of the closure of the Sarnia-Montreal pipeline, some shipping problems on the Interprovincial pipeline, the economic recession which reduced demand for industrial heavy fuel oil and in some markets competition with cheaper natural gas.

Figure 3.1
Domestic Crude Oil Production
(Annual)
000 m^3/d



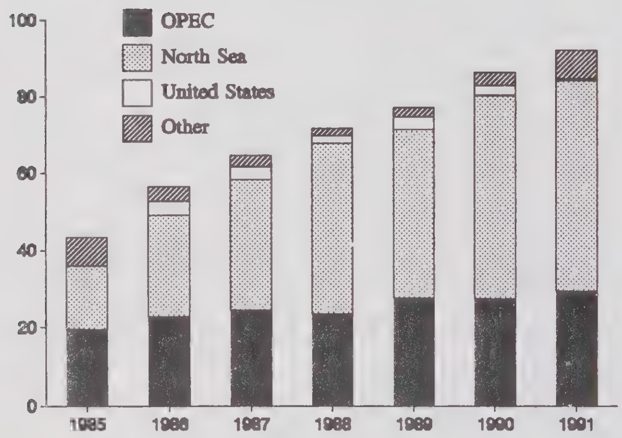
There appears to be some evidence to suggest a modest revival in the heavy oil industry. A new 4 000 m^3/d export pipeline, prompted by an increase in upgrading capabilities in Montana, will provide southern Alberta producers with a new market for surplus heavy crude. As well, the Husky Bi-Provincial upgrader scheduled to start up late in 1992 is expected to convert about 7 000 m^3/d of heavy crude and bitumen into high quality synthetic crude oil.

Based on National Energy Board estimates, domestic production in 1992 is expected to be marginally below that recorded in 1991. The annual production rate of conventional light crude is as expected to continue to decline. This drop should be offset by near capacity synthetic crude oil output and the return of some previously shut-in bitumen production.

3.3 Crude Oil Imports

Deliveries of foreign crude oil to refineries in eastern Canada continued to climb in 1991, reaching an average of 92 000 m^3/d. This was about 6 000 m^3/d higher than in 1990. As shown in figure 3.3, imports have increased rather steadily since the mid-eighties and might have been considerably higher in 1991 were it not for the recessionary slump in oil demand that was largely concentrated in eastern Canada.

Figure 3.3
Imports of Crude Oil by Source
000 m^3/d



As a percentage share of total refinery crude oil receipts, imports rose to 40% by the end of 1991 in comparison to below a 35% share in 1990.

In the Atlantic region, imports (which last year comprised a significant volume of residual oil) rose by about 1 000 m^3/d to approach 50 000 m^3/d. Since crude runs were down from the previous year, the net effect of the incremental imports was to build crude oil inventories over the year by a commensurate amount.

The 7 000 m^3/d rise to 42 000 m^3/d in Quebec reflected the mid-year deactivation of the Sarnia-Montreal extension. Except for a shipment of oil tankered into Montreal from Bent Horn, imports accounted for virtually all crude oil deliveries to Quebec after July of last year.

In Ontario, imports fell to about 500 m^3/d from an average of close to 3 000 m^3/d the year before. The decline resulted from shifts in both demand and supply. On the demand side, Ontario refiners adjusted their receipts of both domestic and imported crude oil downwards to reflect the drop in the region's refined product sales. On the supply side, imports were displaced by the surplus of domestic crude made available to Ontario refiners following the closure of the extension and the loss of the Montreal market.

North Sea deliveries, averaging almost 55 000 m^3/d, accounted for 60% of total imports, two-thirds of which were shipped to Quebec refiners and the remainder to the Atlantic region. OPEC supplied nearly a third of the total imports. About 85% of the 30 000 m^3/d of OPEC supply was destined for the Atlantic region. Saudi Arabia and Nigeria continued to be the major OPEC suppliers. Saudi crude appears to have gained market share at the expense of embargoed Iraqi crude. Demand for Venezuelan crude showed the largest percentage increase. Following the closure of the extension, Montreal refiners turned to Venezuelan (and Mexican) crudes in lieu of Canadian heavy crudes to produce asphalt. Crude imports from the United States dwindled to virtual non-existence by the final quarter of 1991, reflecting the decline in imports into Ontario.

4. Crude Oil Disposition

. Deliveries of crude oil to Canadian refineries declined by 4% in 1991. Reduced deliveries of domestic crude accounted for all of the drop.

. As a result of a drop in domestic demand, Canada's net crude oil export position increased significantly in 1991.

4.1 Canadian Refinery Crude Oil Receipts

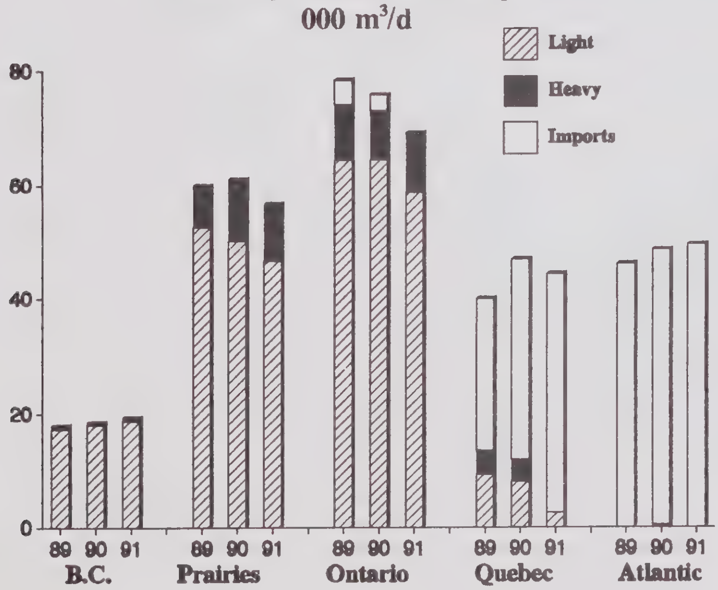
Reflecting the current economic slump and the accompanying drop in demand for refined products, Canadian refiners reduced their demand for crude oil in 1991 by over 4% from the year before. Not all regions, however, saw lower crude oil demand: small increases were recorded in both the Atlantic region and British Columbia. Nationally, crude oil deliveries averaged 240 000 m^3/d, about 11 000 m^3/d below the 1990 level. About 90% of the year-over-year decline occurred in the first half of the year when the fall in refined product demand was particularly severe. Refiners reacted by reducing crude runs and drawing down refined product inventories which had become excessive in light of the slowdown in product demand. Against this backdrop, crude receipts were also curtailed to avoid an unnecessary build of crude oil stocks.

The decline in refined product consumption did abate somewhat in the latter half of the year which partly explains why deliveries of crude oil during that period were only marginally below the previous year. More importantly, crude oil inventories were built in eastern Canada, particularly in the Atlantic region. In fact, the rate of stockbuilding averaged close to 11 000 m^3/d in the fourth quarter.

Refinery demand for domestic crude oil fell to slightly below 149 000 m^3/d in 1991. This amounted to a drop of almost 17 000 m^3/d from the previous year and is the main reason why more crude oil was exported last year than in any year since 1974. The reduction in domestic crude receipts reflected both the current recession generally, and in Quebec, the deactivation of the Sarnia-Montreal extension. Deliveries of domestic crude oil to Montreal via the extension ceased in July. Quebec refiners are now virtually dependent on foreign crude feedstocks although they did run some Canadian crude shipped in by tanker from Bent Horn during the latter half of the year. These shipments normally occur about once a year towards the end of the third quarter when the weather permits navigation in the Arctic.

The cutback in demand affected both domestic light and heavy crude oil deliveries. Light crude deliveries fell 14 000 m^3/d to 127 000 m^3/d while heavy crude demand declined from 24 000 m^3/d in 1990 to 21 000 m^3/d.

Figure 4.1
Refinery Crude Oil Receipts
000 m^3/d



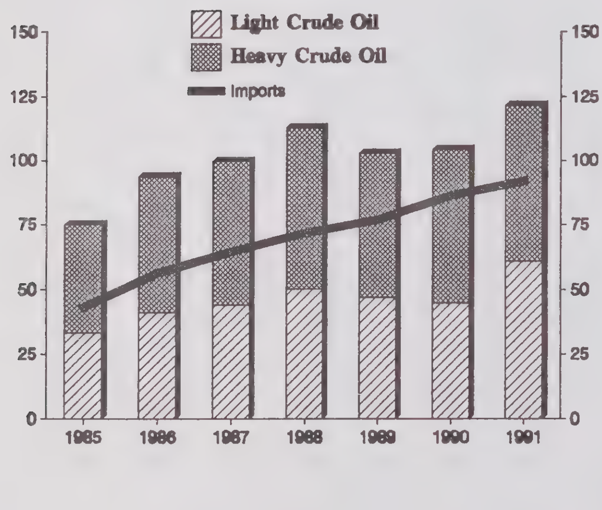
Receipts of conventional light crude fell even further, by almost 18 000 m^3/d down to 94 000 m^3/d. This drop was partially offset by a small increase in condensate deliveries and a 3 000 m^3/d rise to 29 000 m^3/d in synthetic crude receipts - reflecting record levels of synthetic crude production.

The closure of the extension also led to a 6 000 m^3/d increase to 92 000 m^3/d in crude oil imports. A jump of 7 000 m^3/d in Quebec overshadowed a marginal rise in the Atlantic region and a 2 000 m^3/d drop in Ontario. Imports fell below 500 m^3/d in Ontario as the region's refiners took advantage of the surfeit of domestic crude that materialized in the wake of the elimination of the Montreal market.

4.2 Crude Oil Exports

As a result of the decline in demand for indigenous crude oil by Canadian refiners, exports increased by about 17% to 122 000 m^3/d in 1991. Exports peaked in February, during the height of the Gulf crisis, at 144 000 m^3/d. Most of the crude oil was delivered to the United States, particularly to the Chicago area, with small volumes of mainly heavy crude shipped offshore through the port of Vancouver (via Trans Mountain Pipe Line and its Westridge Marine Terminal) to Pacific Rim destinations.

Figure 4.2
Crude Oil Exports
000 m^3/d



Crude exports in 1991 represented about 47% of domestic production (76% of blended heavy supply and 34% of net light crude oil), compared with 40% in 1990. Exports were almost evenly split between light and heavy crudes. Although heavy crude exports remained unchanged from the year before, light crude oil exports recorded a 37% increase over the year before.

Canada's net crude oil export position has been on the decline since 1988. However, as a result the drop in domestic demand, Canada's 1991 net export position, as illustrated in the following table, increased by 65% over 1991. Crude oil exports exceeded imports by about 30 000 m^3/d compared with 18 000 in 1990 - a year of relatively high domestic demand.

If refined petroleum products are included in the calculation, an increase in product exports coupled with relatively flat imports permitted Canada to improve its overall net petroleum export position by 44% or nearly 15 000 m^3/d over that recorded in 1990.

Given that domestic production is expected to remain relatively unchanged in 1992, potential exports will most likely be determined by domestic demand for refined petroleum products and the impact of the closure of the Sarnia-Montreal pipeline.

Table 4.1
Net Crude and Product Export Position
000 m^3/d

	1991	1990	% Change
Crude Oil			
Exports	121.8	104.0	17%
Imports	92.0	86.3	6%
	-----	-----	-----
Net Crude Exports	29.8	18.0	65%
Products			
Exports	42.1	38.3	10%
Imports	23.4	22.7	3%
	-----	-----	-----
Net Product Exports	18.7	15.6	20%
Net Export Position	48.5	33.6	44%

5. Pipeline Deliveries

. Trans Montain Pipe Line's Low Point oil-port and pipeline project on the Olympic Peninsula has been cancelled for the second time since 1981.

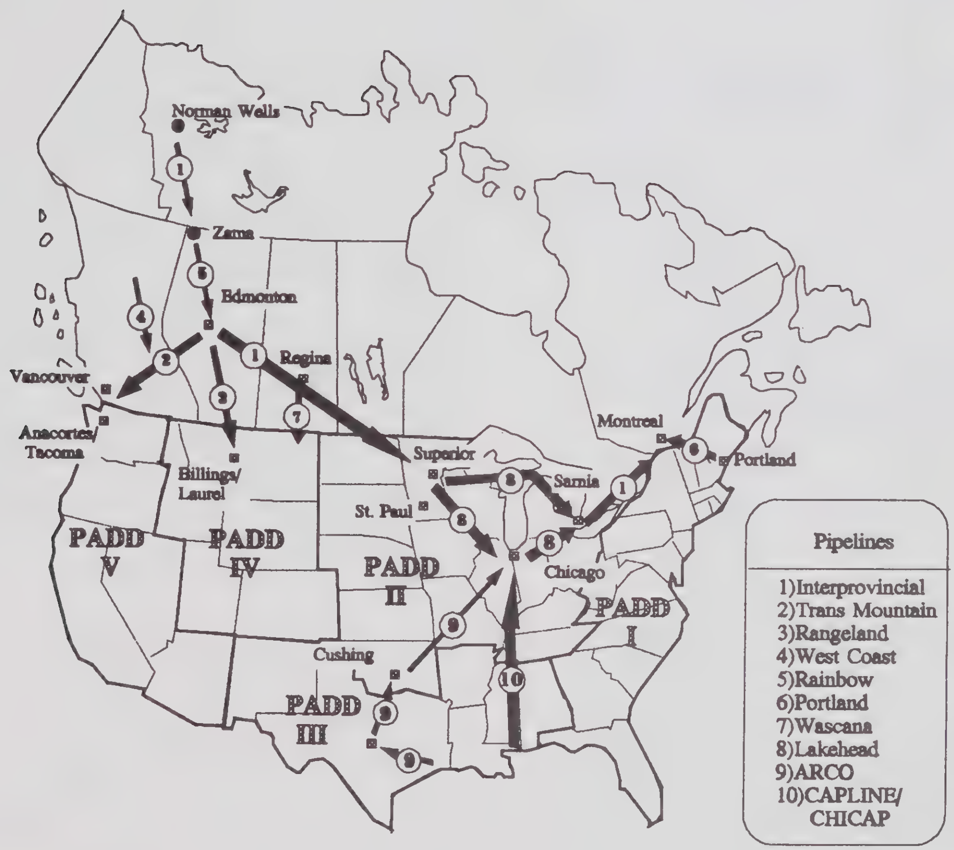
. The National Energy Board is expected to render a decision on the tolls for a reversal of the Sarnia-Montreal pipeline and related issues by mid-1992.

Most Canadian crude oil is gathered at Edmonton Alberta. It is then delivered to the domestic and export markets, for the most part, by a network of pipelines.

The bulk of Canadian crude exports are delivered to the United States via the Interprovincial (and Lakehead) pipeline system. Smaller volumes are delivered by the Trans Mountain Pipe Line to the west coast for delivery to large U.S. refineries in the Puget Sound area and tankering offshore. The Rangeland carries crude oil south into Montana.

Canadian crude oil delivered to the U.S. midwest competes in the key Chicago refining area with U.S. domestic crudes and other foreign crudes delivered through the CAPLINE/CHICAP pipeline system from the Louisiana Gulf Coast and alternatively the Arco pipeline system from Texas, Gulf Coast via Cushing, Oklahoma.

Figure 5
Major Crude Oil Pipelines



5.1 Trans Mountain Pipe Line Deliveries

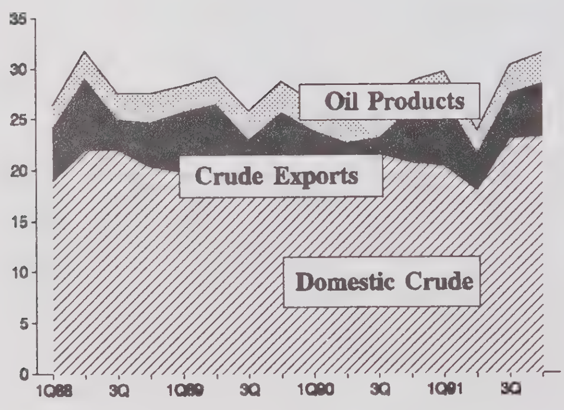
The Trans Mountain Pipe Line (TMPL) originates in Edmonton and delivers crude oil, semi-refined and refined petroleum products some 1328 kilometres west to the Vancouver area. The pipeline also receives crude from northern British Columbia at Kamloops delivered via the West Coast Pipe Line.

Total TMPL deliveries of crude oil and products over 1991 averaged 29 000 m^3/d, up about 2 000 m^3/d from the year before. This increase in throughput was for the most part the result of a rise in the delivery of crude oil for export.

Crude oil and semi-refined product deliveries to the Vancouver/Burnaby area increased marginally from the previous year to 21 000 m^3/d. While crude deliveries at 17 000 m^3/d were up by about 2 000 m^3/d, deliveries of semi-refined products declined to just under 4 000 m^3/d. Refined petroleum products deliveries to Kamloops B.C. held at about 3 000 m^3/d.

TMPL deliveries of crude oil destined for the export market totalled just over 5 000 m^3/d in 1991, compared with nearly 4 000 m^3/d a year earlier. About 90% of this volume was delivered to the pipeline's Westridge Marine Terminal for tankering offshore. Deliveries to Washington state refineries accounted for the remainder.

Figure 5.1
Trans Mountain Deliveries
000 m^3/d



A recent company forecast suggests a modest increase in throughput for 1992. However, deliveries of heavy crude for export which accounted for about two thirds TMPL exports in 1991 are expected to be significantly reduced due to the potential shut-in of large volumes of heavy crude and increased upgrading capabilities in both western Canada (Bi-provincial upgrader) and the United States. The forecast also suggests that reduced demand in eastern Canada could result in increased export deliveries of light crude.

TMPL's Low Point oil-port and pipeline project in Washington state has been cancelled for the second time since 1981. According to a recent announcement, the company plans to abandon its US$600-million project after two major U.S. refineries declined to support the project. The project was also opposed by several state environmental and citizen groups.

The project would have included an offshore terminal near Low Point on the Olympic Peninsula and pipeline for the movement of Alaska and foreign crude to four major Washington state refineries. Plans to use the facility to export Canadian crude to U.S. and Pacific Rim markets through the company's U.S. extension that now serves these refineries, with a parallel outbound-line to the terminal were shelved earlier due to declining export potential for Canadian heavy crude.

5.2 Interprovincial Pipe Line Deliveries

The Interprovincial Pipe Line (IPL) system consists of three major sections stretching some 3 700 kilometres from western Canada east to Montreal, Quebec.

The western section of the IPL originates at Edmonton and travels east through Regina, Saskatchewan and crosses into the United States near Gretna, Manitoba. The Lakehead Pipe Line (which on behalf of IPL owns 20% of the assets) manages the pipeline which serves the U.S. Great Lakes region via routes to the north and south of Lake Michigan to Sarnia, Ontario. The eastern section of the IPL from Sarnia to Montreal was closed in July of 1991 due to falling throughput. However, two lines to the Toronto area remain active.

Deliveries on the Sarnia-Montreal pipeline began to decline late in 1990 from nearly 20 000 m^3/d early in the year to about 5 000 m^3/d by year end. Citing increasing competitiveness of offshore crudes, shippers advised IPL that they intended to terminate domestic crude deliveries during the first quarter of 1991. As a result, IPL began to plan for the idling and deactivation of the line which at its peak in 1979/1980 delivered nearly 50 000 m^3/d to Montreal refineries. By August, IPL had drained all the remaining crude from the line and filled it with nitrogen.

Despite the closure of the Sarnia-Montreal pipeline, total IPL deliveries in 1991 averaged 224 000 m^3/d compared with 226 000 m^3/d the year before. In 1990, IPL delivered 101 000 m^3/d to eastern Canada with 95 000 m^3/d shipped to the United States. While total IPL deliveries were slightly higher the year before, in 1991 U.S. markets received the lion's share of IPL deliveries at 109 000 m^3/d with shipments to eastern Canada falling 17% to 83 000 m^3/d.

With the closure of the line Montreal refiners have become almost entirely dependent upon foreign crude. Over the latter half of the year, the drop in domestic deliveries was offset by a corresponding increase in crude imports.

A number of options were considered by IPL for the closed line. Some consideration was given to the periodic shipment of small volumes of heavy crude to Montreal as well as using the line to transport low pressure natural gas. IPL's preferred option is line reversal which would allow for the delivery of imported crude from Montreal to Toronto and Sarnia.

The National Energy Board (NEB) which regulates pipelines in Canada completed public hearings in February, 1992 on the toll methodology that would be applied to the reversed line. The NEB is expected to render a decision on this toll design as well as other key issues relating to the line reversal at the end of the second quarter or early in the third quarter of 1992.

Figure 5.2.1
IPL Deliveries
000 m^3/d

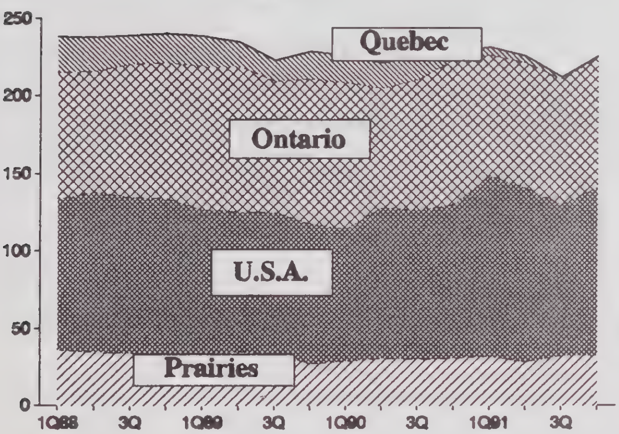
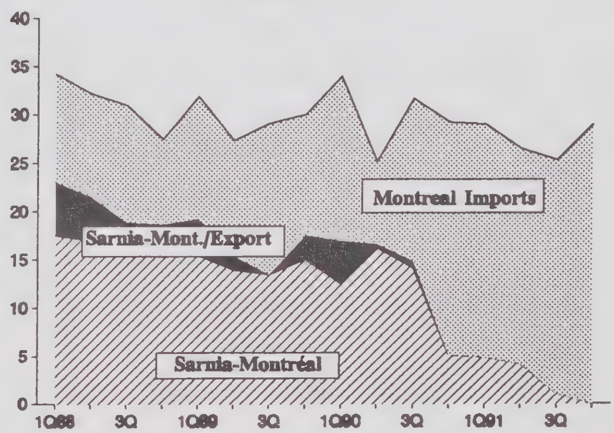


Figure 5.2.2
Deliveries to Montreal
000 m^3/d



Note: The Sarnia-Montreal pipeline extension was built at a cost of about $250-million in 1976, during a period of considerable instability in world oil markets characterized by a period of high and volatile prices. The government of the day sought to insulate the Canadian economy from the unpredictable international oil market. One policy was to regulate oil prices in Canada at levels below prevailing world oil prices. Oil prices were roughly equalized across Canada by imposing duties on crude oil exports and subsidizing imports. Another policy was to reduce Canada's dependence on crude oil imports by extending the IPL as far as Montreal. Prior to the construction of the line refiners in the Atlantic region and Montreal were virtually dependent upon foreign supplies for crude oil feedstock. The extension also provided an additional market for western Canadian crude oil at a time when the government began limiting light crude oil exports.

6. Refinery Activity

. *As a result of declining consumer demand for petroleum products in 1991, the national refinery utilization rate fell to 80%.*

. *Over the last few years environmental concerns have driven most changes in the Canadian refining industry.*

6.1 Throughtput and Utilization Rates

Total capacity of all operating refineries in Canada averaged 313 000 m^3/d in 1991. Capacity was up by about 3 000 m^3/d over the year before due to some modest expansion in the Atlantic region and Ontario. With product demand down, refinery throughput fell nearly 12 000 m^3/d to 251 000 m^3/d. As a result, the national refinery utilization rate dropped to 80% from 85% in 1990. (See table 6 for capacity details.)

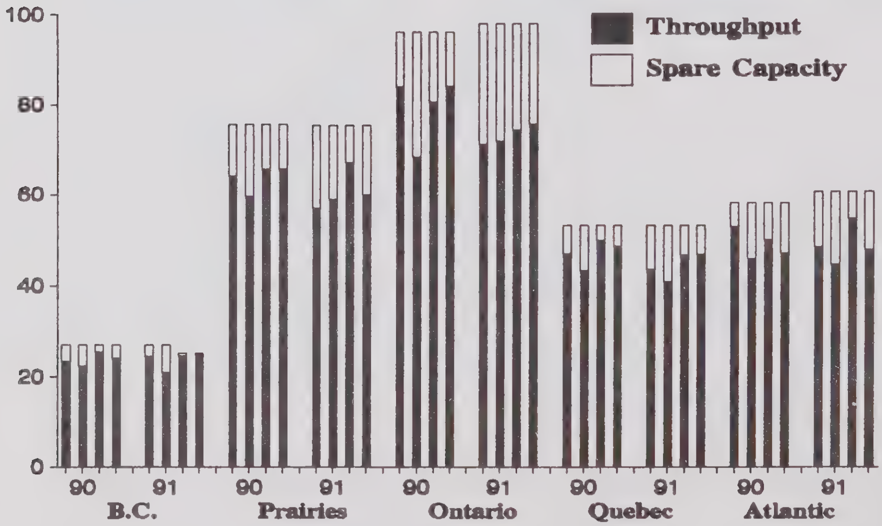
Refinery utilization was down across all regions with the exception of British Columbia. The largest drop was recorded in Ontario were utilization fell to about 75% from 82% the year before. In British Columbia the utilization rate increased to about 91%, the highest in Canada. This increase was due to the closure of a small 3 000 m^3/d refinery in Taylor, B.C. which was used largely to supply transportation fuels and asphalt to the northeastern part of the province. This closure marked the first since a number of refineries were closed in the early to mid-eighties due a recession-driven drop in product demand.

There are indications that slumping demand could force Canada's biggest integrated oil companies into a new round of restructuring and refinery closures. According to the Petroleum Monitoring Agency the refining and marketing business was battered in 1991 with a net income loss of $ 1.9 billion. (See Section 10 for further detailed information.)

Any improvement in the refining industry will likely depend on the strength of the economy in 1992 and a rise in consumer demand for refined products. Other factors include ongoing company rationalization and general cost reduction programs. For example early in 1992 Petro-Canada announcing the sell-off or shutting of more than 1 000 gasoline stations across the country and the closing of two of its refineries and the possible sale of a third.

The Petro-Canada refinery closures are expected to remove about 12 000 m^3/d in total refining capacity from the Canadian scene. Industry analysts expect other major companies to make similar announcements as a 'radical reshaping' of the refining and marketing industry continues through 1992.

Figure 6.1
Regional Refinery Utilization and Capacity
(1st Quarter 1990 to 4th quarter 1991)
000 m^3/d



6.2 Developments in Canadian Refining

Over the last several of years environmental concerns have driven most changes in the Canadian refining industry. Aside from the start up of Consumer's Co -Op's NewGrade heavy crude upgrader, no significant throughput capacity has been installed. With the exception of some incremental changes and the derating of a few refineries by the end of 1991 throughput capacity had only risen by about 4% from 1987.

Environmental concerns have been on the rise and have had an increasing impact on the refining industry. The industry became particularly concerned with the phase out of lead in motor gasoline and the likely reduction of sulphur in diesel fuel. As well, more importance was placed on the need for increased refinery process monitoring and tighter control of air and water emissions.

The advancement of the gasoline lead phase out date by one year had a significant impact on the refining industry. Effective December 1, 1990 lead as an additive used to improve the octane rating of gasoline was banned. The changed product specification resulted in accelerated efforts by refiners to have processing and blending capabilities in place to meet the new deadline.

In response to lead phase out, refiners were charged with balancing the cost effectiveness of their operations with meeting the new environmentally-dictated product specification. The gasoline specification change required modification to existing refinery processes and for some the addition of isomerization units, the process of choice for many refiners.

The issue of diesel fuel sulphur reduction which has been under scrutiny by both government and industry, still remains unresolved. Although Environment Canada has proposed that the sulphur content of diesel fuel be reduced to meet future engine emission standards there still remains some doubt as to the amount of fuel concerned, the time it would take to effect the product change and the cost to the industry.

The refining industry has also been affected by provincial requirements to update air and water emission standards. These changes have required substantial industry investment, for the most part, involving the update of refinery process control equipment with little contribution to final refined product yield or quality.

In addition, the Canadian refining industry has been closely examining the newly revised U.S. legislation on clean air. Although not directly affecting Canadian refiners, its provisions could be considered and adopted by our environmental regulators. Among other things, refiners could be required to make further costly changes in gasoline blending due to reductions in benzene and aromatic content.

For further information on this subject please contact the *Petroleum Technology Division* of Energy, Mines and Resources.

(613-992-2916)

Table 6 REFINING CAPACITY IN CANADA (December 1991)

Process unit capacities in 000 m^3/d

COMPANY	CITY	PROVINCE	CRUDE	VACUUM	VISBREAKER	COKER	FCCU	HCU	RESID UPGRADER	NAPHTHA HTU
ATLANTIC REGION										
NFLD REFINING	Come-By-Chance	NFLD	16700	8900	0	0	0	5560	0	4100
ESSO PETROLEUM	Dartmouth	NS	13100	6360	0	0	3970	0	0	1510
ULTRAMAR	Halifax	NS	3180	1370	0	0	1140	0	0	570
IRVING OIL	Saint John	NB	27700	9810	2860	0	2720	4720	0	7220
			60680	**26440**	**2860**	**0**	**7830**	**10280**	**0**	**13400**
QUEBEC REGION										
PETRO-CANADA	Montreal	QUE	14300	6470	2000	0	2730	2290	790	4230
SHELL CANADA	Montreal	QUE	19070	7850	1910	0	4000	1860	0	5430
ULTRAMAR	St Romuald	QUE	19800	8740	0	0	5500	0	0	3710
			53170	**23060**	**3910**	**0**	**12230**	**4150**	**790**	**13370**
ONTARIO REGION										
ESSO PETROLEUM	Nanticoke	ONT	16900	4930	0	0	6360	0	0	4080
ESSO PETROLEUM	Sarnia	ONT	19310	4530	0	3340	3970	1650	0	5130
PETRO-CANADA	Clarkson	ONT	9530	5460	0	0	0	0	0	1640
PETRO-CANADA	Oakville	ONT	12800	6520	0	0	4040	0	0	3100
POLYSAR	Sarnia	ONT	17000	6360	0	0	0	0	0	0
SHELL CANADA	Sarnia	ONT	11280	3920	640	0	2290	1070	0	2380
SUNCOR	Sarnia	ONT	11200	2600	1000	0	2540	3180	0	4070
			98020	**34320**	**1640**	**3340**	**19200**	**5900**	**0**	**20400**
PRAIRIE REGION										
CO-OP/NEWGRADE	Regina	SASK	7180	3650	0	1320	3000	0	4300	2150
SASK ASPHALT	Moose Jaw	SASK	2110	1160	0	0	0	0	0	0
ESSO PETROLEUM	Edmonton	ALTA	26200	11830	0	0	8400	0	0	9130
PETRO-CANADA	Edmonton	ALTA	19310	4290	0	1130	6360	3000	0	1500
HUSKY	Lloydminster	ALTA	3650	1870	0	0	0	0	0	0
PARKLAND	Bowden	ALTA	950	0	0	0	0	0	0	480
SHELL CANADA	Scotford	ALTA	10872	0	0	0	0	6150	0	3600
TURBO RESOURCES	Balzac	ALTA	4640	1210	0	0	1840	0	0	1650
ESSO PETROLEUM	Norman Wells	NWT	510	0	0	0	0	0	0	0
			75422	**24010**	**0**	**2450**	**19600**	**9150**	**4300**	**18510**
BRITISH COLUMBIA REGION										
CHEVRON	Burnaby	BC	7150	1490	0	0	1700	0	0	1590
ESSO PETROLEUM	IOCO	BC	7200	3800	0	0	1950	0	0	1110
PETRO-CANADA	Port Moody	BC	3970	3480	0	0	0	0	0	2450
PETRO-CANADA *	Taylor	BC	2860	250	0	0	1000	0	0	640
HUSKY	Prince George	BC	1530	640	0	0	460	0	0	200
SHELL CANADA	Burnaby	BC	3810	1110	0	0	890	0	0	860
			26520	**10770**	**0**	**0**	**6000**	**0**	**0**	**6850**
TOTAL CANADIAN CAPACITY			**313812**	**118600**	**8410**	**5790**	**64860**	**29480**	**5090**	**72530**

* refinery closed mid-1991

Table 6 (continued)

REFORMER LOW PRESSURE	REFORMER CONVENTIONAL PRESSURE	DIST HTU	OTHER HTU	ALKYLATION HF	ALKYLATION H2SO4	POLY	ISOMERIZATION C4	ISOMERIZATION C5C6	AROM EXTRACTION	LUBES	ASPHALT
0	4100	4000	0	0	0	0	0	0	0	0	0
1510	0	4080	1430	0	0	410	0	0	0	0	790
0	570	830	0	0	0	0	0	0	0	0	0
0	5510	6440	0	0	954	270	0	1510	0	0	1860
1510	**10180**	**15350**	**1430**	**0**	**954**	**680**	**0**	**1510**	**0**	**0**	**2650**
0	4970	1430	0	0	380	130	0	0	1140	0	2270
0	3290	4290	0	400	0	0	0	1200	0	490	1140
0	2700	2380	0	0	0	620	0	1510	0	0	4770
0	**10960**	**8100**	**0**	**400**	**380**	**750**	**0**	**2710**	**1140**	**490**	**8180**
3925	0	0	0	1180	0	0	0	0	0	0	0
2270	2110	2110	3920	1080	0	670	0	0	0	990	0
1560	0	940	0	0	0	0	0	1100	0	780	730
0	2200	1000	0	0	490	0	0	0	0	0	1510
0	0	0	2380	0	0	0	0	0	2860	0	0
0	3650	1000	0	0	0	250	0	0	430	0	0
0	4240	760	0	810	0	0	0	0	1600	0	400
7755	**12200**	**5810**	**6300**	**3070**	**490**	**920**	**0**	**1100**	**4890**	**1770**	**2640**
0	1430	1000	0	950	0	300	0	430	0	0	0
0	0	0	0	0	0	0	0	0	0	0	870
3700	0	0	2380	2180	0	0	1060	0	0	510	1500
0	1450	5900	1160	1510	0	0	480	1450	0	0	0
0	0	0	0	0	0	0	0	0	0	0	1870
0	480	480	0	0	0	0	0	480	0	0	0
3600	0	3180	0	0	0	0	0	0	950	0	0
0	1310	1200	2110	0	0	400	0	500	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
7300	**4670**	**11760**	**5650**	**4640**	**0**	**700**	**1540**	**2860**	**950**	**510**	**4240**
0	1590	0	0	0	320	100	0	0	0	0	400
1110	0	850	850	0	0	290	0	0	0	0	200
0	1370	2240	0	0	0	0	0	0	0	0	0
0	475	1140	0	160	0	0	0	0	0	0	80
0	200	910	0	0	0	0	0	150	0	0	210
0	540	1590	0	0	0	110	0	0	0	0	410
1110	**4175**	**6730**	**850**	**160**	**320**	**500**	**0**	**150**	**0**	**0**	**1300**
17675	**42185**	**47750**	**14230**	**8270**	**2144**	**3550**	**1540**	**8330**	**6980**	**2770**	**19010**

7. Crude Oil and Petroleum Product Stocks

. Stocks of crude oil and refined petroleum products closed 1991 relatively unchanged from the year before.

Primary stocks of crude oil and refined petroleum products closed 1991 at 14.7 million m^3, unchanged from a year earlier. Of this volume, refined product stocks fell slightly to 11.7 million m^3 with crude oil stocks accounting for the remainder.

Falling product demand and an increase in refinery production, in the latter half of the year, enabled product stocks to recover. Despite a weak economy and a relatively mild winter, end-of-year stocks approached that of a year earlier. Product demand over the year averaged 216 000 m^3/d, 6% below a year earlier.

On a year-over-year basis stock changes were for the most part concentrated in the Atlantic region were crude and petroleum product stocks increased by 5% and 15% respectively. Although products were also up in the Prairies this rise was countered by product stock decreases of 7% in Quebec and 16% in Ontario.

Among petroleum products, light fuel oil (LFO) stocks increased significantly as a sluggish economy offset seasonal demand for heating oil. By year-end LFO stocks had reached the highest level since 1986. This increase was more than offset by decreases in motor gasoline and diesel fuel oil stocks while other products such as asphalt, jet fuel and petrochemical feedstock increased marginally.

By the end of December, total crude oil and petroleum product stocks * represented a reserve of about 71 days of supply (based on historical consumption), compared with 65 days of supply a year earlier.

Figure 7.1
Crude and Product Stocks
(End of quarter)

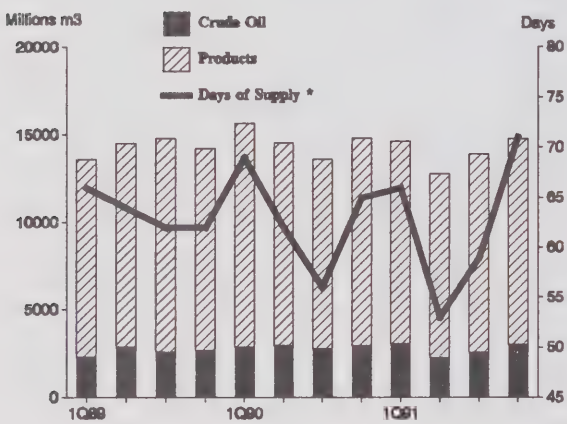
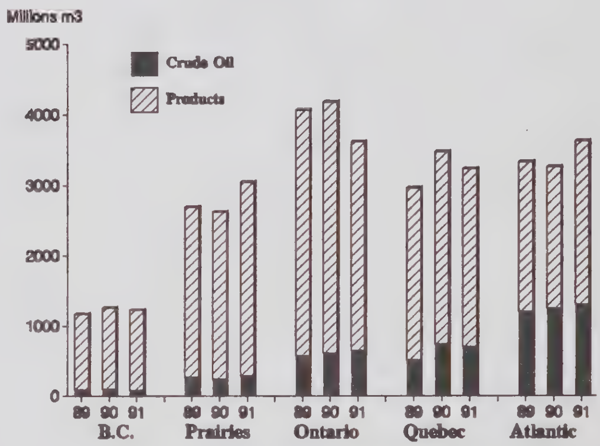


Figure 7.2
Crude and Product Stocks by Region
(End-of-Year)



* *Stocks do not include estimates of crude oil held in pipelines/tankage. If these stocks were to be included it is estimated that the number of days of supply would increase by about seven days.*

Figure 7.3
Total Petroleum Product Stocks
million m^3

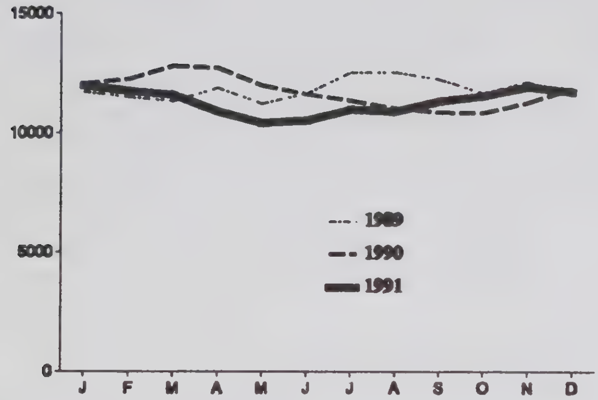


Figure 7.4
Motor Gasoline Stocks
million m^3

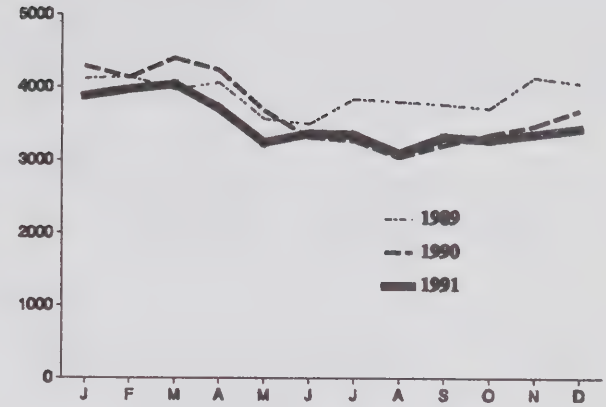


Figure 7.5
Light Fuel Oil Stocks
million m^3

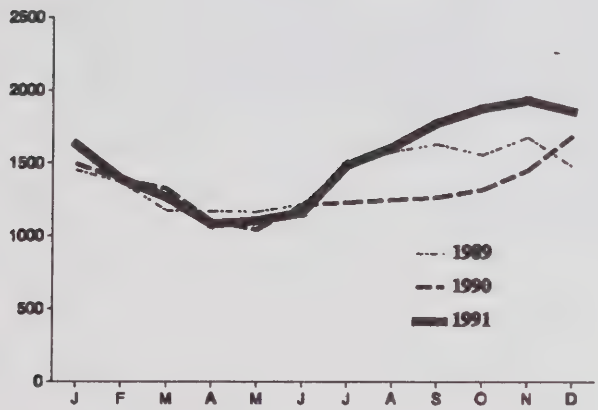


Figure 7.6
Diesel Fuel Oil Stocks
million m^3

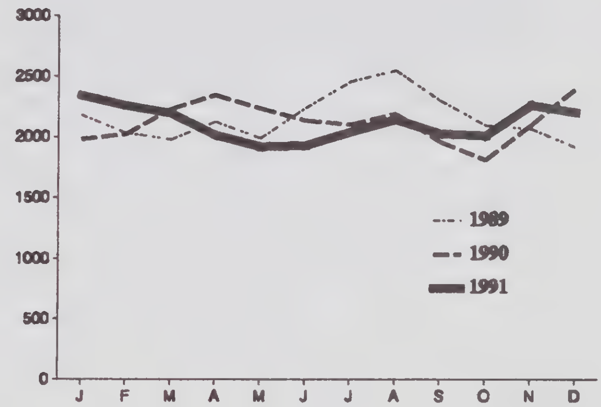


Figure 7.7
Heavy Fuel Oil Stocks
million m3

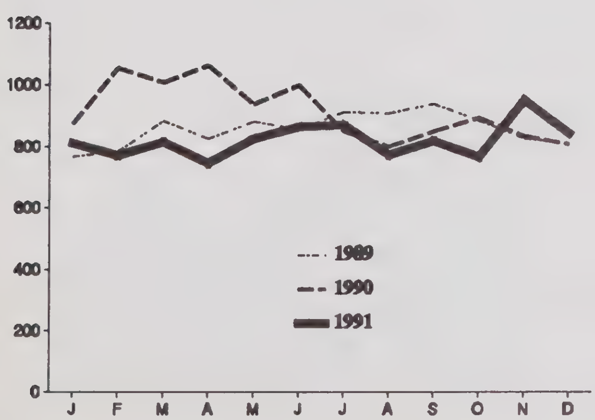
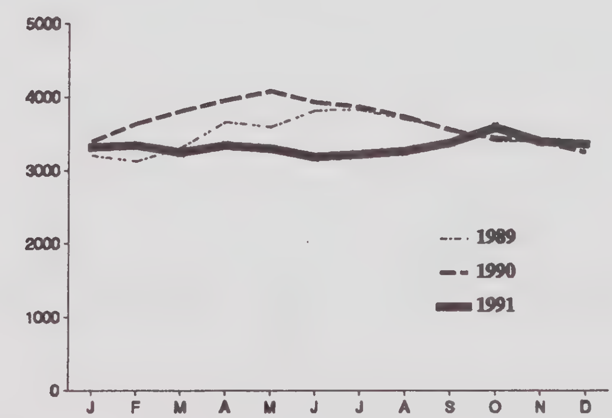


Figure 7.8
Other Petroleum Product Stocks
million m^3



8. Crude Oil Prices

. *International and domestic crude oil prices in 1991 were affected by political and economic developments.*

. *After a steep fall early in 1991 crude oil prices firmed marginally over the last several months of the year.*

8.1 International Crude Oil Prices

Spot crude oil prices were volatile in 1991, largely due to the effects of political and economic developments. The volatility in spot crude oil prices was reflected in the price of West Texas Intermediate (WTI), which ranged from a high of $28.15/bbl, to a low of $19.55/bbl (weekly averages). Over the year, WTI averaged $21.60/bbl, down $2.85/bbl from the average 1990 price.

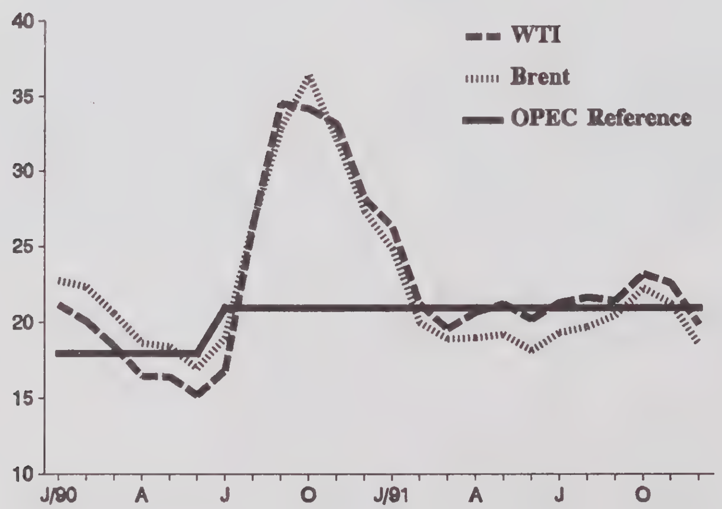
During the first quarter of 1991, the Persian Gulf situation dominated world oil markets. Spot crude oil prices were driven by rumours and speculation emanating from the Persian Gulf. Nevertheless, as oil supplies were adequate, prices began their downward plunge with the Allied forces' defeat of Iraq. WTI averaged $22.35/bbl over the quarter.

In the second quarter, prices weakened considerably from the highs recorded in the first quarter. The combined effects of the economic recession in industrialized countries, in particular the U.S., abundant oil inventories, and the continued high level of OPEC crude oil output worked to weaken prices. Over the quarter, spot WTI averaged $20.75/bbl, a decrease of $1.60/bbl from first quarter 1991 levels.

Spot crude oil prices did, however, firm slightly in the third quarter as oil supply/demand fundamentals once again drew oil market attention. Other factors also influenced stronger prices, including: improved economic activity in industrialized countries; uncertainty surrounding former Soviet oil supplies; the unlikely return of Iraq and Kuwait to world oil markets; and a lack of spare crude oil productive capacity within OPEC. During the quarter, spot WTI rose $0.75/bbl above its second quarter price, to $21.45/bbl.

Prices continued to strengthen in the fourth quarter, rising $0.45/bbl from the third quarter average, to $21.90/bbl. Crude oil prices did, however, begin to decline by the end of the quarter due to an oversupplied market. The continuing high level of OPEC crude oil production, the lack of extremely cold weather during the northern hemisphere winter, and no major oil supply disruptions, also eased the upward pressure on crude oil prices.

Figure 8.1
International Crude Oil Prices
US$/barrel

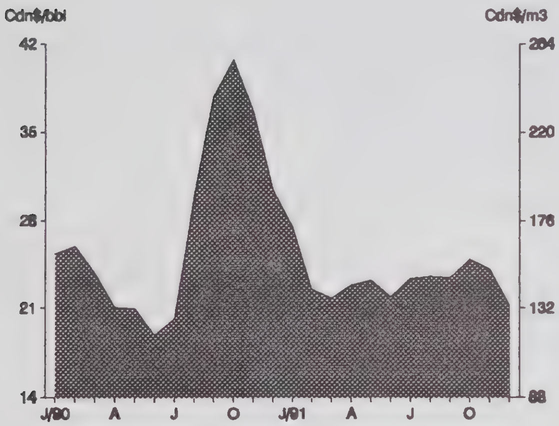


8.2 Domestic Crude Oil Prices

Canadian oil prices were relatively stable, for the most part, in 1991. After a steep fall early in the year, prices firmed marginally through to October, declining again in December.

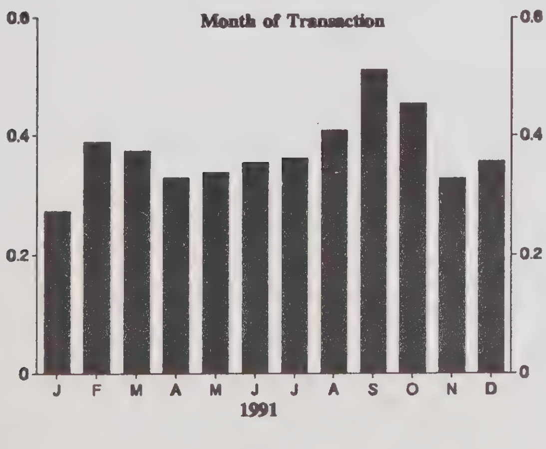
The price for Edmonton Par crude oil (40°API, 0.5% sulphur), as posted by refiners, averaged \$23.37/bbl (US\$20.40/bbl) in 1991.

Figure 8.2.1
Canadian Par Crude Oil Postings



Canadian crude oil prices continue to track international prices, primarily the U.S. benchmark crude West Texas Intermediate (WTI). Differentials between WTI and Canadian Par crude at Chicago increased in the third quarter to \$0.43/bbl from a first half average of \$0.34/bbl. The increase is attributable, in part, to weak demand from the prolonged recession and a generally oversupplied market. The differential in the fourth quarter narrowed to \$0.37/bbl.

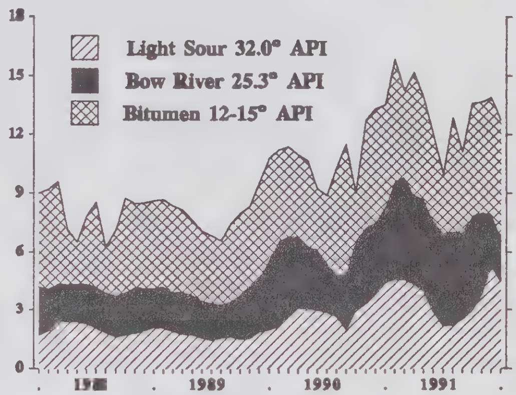
Figure 8.2.2
Canadian Par vs WTI NYMEX
CDN \$/bbl



8.3 Domestic Crude Oil Price Differentials

The following graph illustrates the crude oil price differentials between Edmonton Par crude oil and the average posted prices of Alberta Light Sour, Bow River (heavy) and bitumen.

Figure 8.3
Domestic Crude Oil Differentials
(Cdn \$/bbl)



After averaging \$4.14/bbl during the first half of 1991, the sour crude differential (Par - Light Sour) dropped to a more traditional level of \$2.30/bbl in the third quarter, only to rebound to a fourth quarter average of \$4.03/bbl. High fourth quarter differentials were a result of a number of bearish factors affecting sour crude prices including recessionary pressures, IPL apportionment, a greater availability of light sweet Canadian crude oil, mild weather in North America and lower than expected fourth quarter demand.

Heavy crude oil price differentials (Par - Bow River) while remaining higher than pre-Gulf crisis levels followed seasonal demand patterns. The differential dropped to an average \$7.03/bbl in the third quarter and increased in the fourth quarter to \$7.99/bbl.

The differential between Par and bitumen prices followed a similar pattern to the heavy crude oil differentials in the last half of 1991. From a first half average of \$14.14/bbl the differential narrowed to \$11.33/bbl during the third quarter and then increased to an average \$13.74/bbl in the fourth.

9. Petroleum Product Prices

. *By mid-1991 petroleum product prices had returned to pre-Gulf war levels after reaching their highest level in recent history early in the year.*

. *Reductions in the crude oil cost component of motor gasoline and industry margins were partially offset by higher consumption taxes in 1991.*

9.1 Price Trends

Triggered by the Persian Gulf war, petroleum product prices in January 1991 rose to their highest levels in recent history. High prices were sustained through January and began to decline almost as soon as the war ended in mid-February.

By mid-1991, product prices had returned to their pre-war levels in most centres. Rapid price declines were most prominent in Toronto, Regina, Calgary and Edmonton where price wars flourished. Despite relatively stable prices in Atlantic Canada, lower prices in the west forced the Canadian average down.

Regular unleaded gasoline fell 10 ¢/litre over the year. Diesel oil dropped 6 ¢/litre with the largest decreases (greater than 10 ¢/litre) recorded in Charlottetown, Halifax and Vancouver.

Despite the imposition of the federal Goods and Service Tax (GST), furnace fuel oil (FFO) which was previously tax-exempt, dropped 8.5 ¢/litre. The GST component of the price was 3 ¢/litre in January, gradually lowering to 2.4 ¢/litre by year-end.

Propane prices increased in some centres while in the Prairies and Toronto prices dropped by more than 5 ¢/litre. Similar to gasoline and diesel, lower prices in the western markets and Toronto offset high prices in Atlantic Canada. The average Canadian propane price fell 3.6 ¢/litre over the year.

9.2 Gasoline Cost Components

An examination of pump price components for regular unleaded gasoline indicates that reductions in crude costs and industry margins were partially offset by higher consumption taxes in 1991 (Figure 9.2).

Figure 9.1
1991 Average Canadian Retail Prices
(In Major Centres)
cents/litre

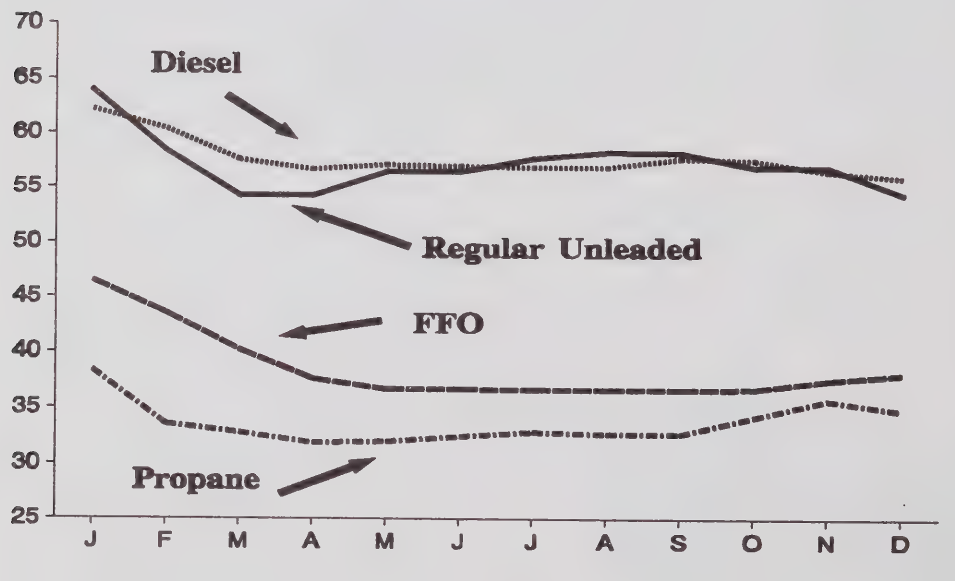
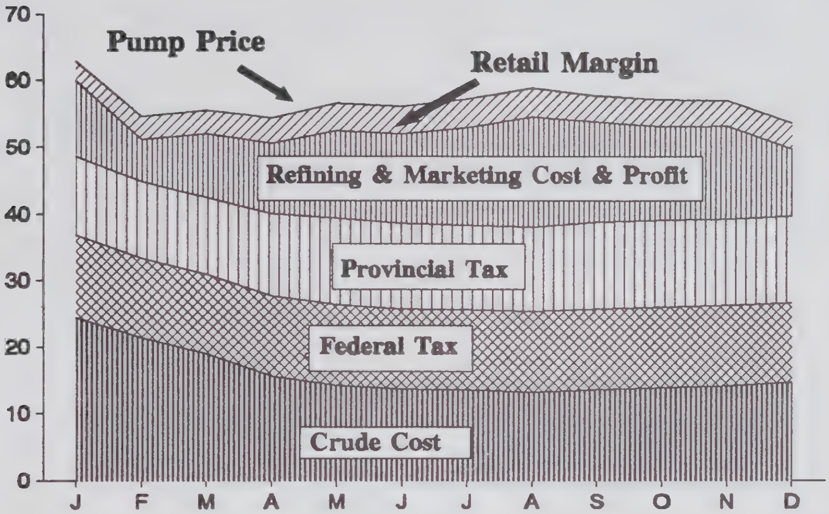


Figure 9.2
Average Canada Pump Price Components
(Regular Unleaded Gasoline at Self-Serve)
cents/litre



Over the twelve-month period from December 1990 to December 1991, average Canadian crude costs decreased from 25.9 ¢/litre to 14.8 ¢/litre. In December 1991, crude costs accounted for 28% of the retail price, down from 40% in 1990.

As pump prices declined over the year, taxes accounted for an increasing share of the price. Decreases in the federal GST component were more than offset by provincial tax increases. Combined federal and provincial taxes rose by 1.3 ¢/litre during 1991 and represented 46% of the average retail price in December, compared to 37% in December 1990.

The residual component, refining and marketing costs and profits, fluctuated from a low of 6.3 ¢/litre in February to a high of 16.5 ¢/litre in August and ended the year at 10.5 ¢/litre, down nearly a cent from December 1990. Retail margins were relatively stable during the year, ranging from 4.3 ¢/litre to 3.4 ¢/litre.

9.3 Crude Oil Costs

Crude oil costs as a component of motor gasoline prices are based on the actual refinery gate price of crude received in any given month. By using refinery acquisition costs the need to estimate the time required to transport crude from the wellhead to the refinery gate is eliminated. However, there is still a delay between receiving the crude at the refinery gate and transporting the finished product to the marketplace. Using average turnover times for crude and product inventories, that lag is calculated to be between 45 and 62 days. For simplicity, a two-month lag is assumed in processing crude and delivering product to the consumer.

Crude oil cost analysis has some limitations particularly during periods of price volatility. Even when the market is stable individual company positions can exhibit considerable variation. Local market conditions, especially variations in stock levels among companies, have a significant impact on the rapidity of product price change.

In addition, imports of motor gasoline and other refined products have steadily increased over the last five years. Canadian markets are influenced by sudden changes in international refined product prices. More rapid price changes in the United States have put pressure on Canadian pump prices, especially in border areas.

Figure 9.3 illustrates the cumulative changes in the average ex-tax price of regular unleaded gasoline over

the last two years, compared to cumulative changes in crude oil costs. Actual crude costs, with no lag, as well as crude costs lagged by 60 days are shown. This graph shows that product and crude markets were, at times, quite independent, with product prices moving in the opposite direction to crude prices.

In the short term, local market conditions are more important than crude costs in determining product prices. Nevertheless, in the longer term, there will be some correlation between the price of refined products and the cost of the crude oil from which they are made.

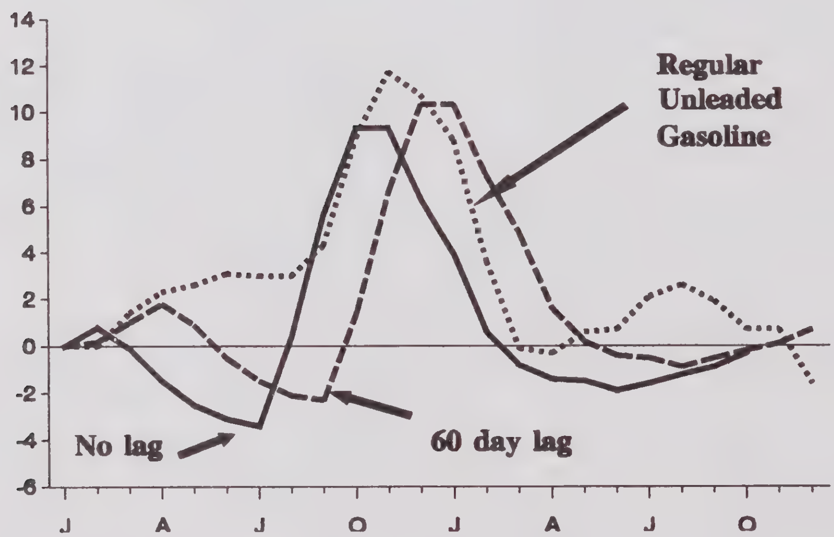
During the last year, several major oil companies have been working toward shortening the time it takes for product prices to reflect changes in crude costs. Some companies have changed their accounting method so that inventory value is adjusted to reflect replacement cost rather than the original cost at the time of purchase. This could lead to a faster flowthrough of crude oil price changes.

However, it can be difficult to establish a direct correlation between crude costs and retail prices since many other factors influencing product prices often move in the opposite direction to crude costs and can counteract those changes.

9.4 Consumption Taxes on Petroleum Products

On January 1, 1991, the federal government imposed the Goods and Services Tax (GST), a 7% tax applied at the retail level. The initial impact of the GST was an average increase in federal taxes of 0.4 ¢/litre on regular unleaded gasoline. The diesel tax increased by 0.8 ¢/litre. Furnace fuel oil which was not subject to a federal tax previously, experienced a price increase of 3.0 ¢/litre as a result of the new tax. These increases cannot be attributed solely to the GST since, as a result of the situation in the Persian Gulf, all product prices were at their highest levels in several years.

Figure 9.3
Cumulative Price Changes Since January 1990
(excluding taxes)
cents/litre



As the product prices dropped after the first quarter, federal taxes dropped accordingly. At year-end, the federal tax on regular unleaded gasoline was lower than the 1990 level. Diesel incurred an increase of 0.5 ¢/litre from the end of last year due to sustained higher retail prices. The GST on furnace fuel oil had stabilized at 2.4 ¢/litre by the end of the year.

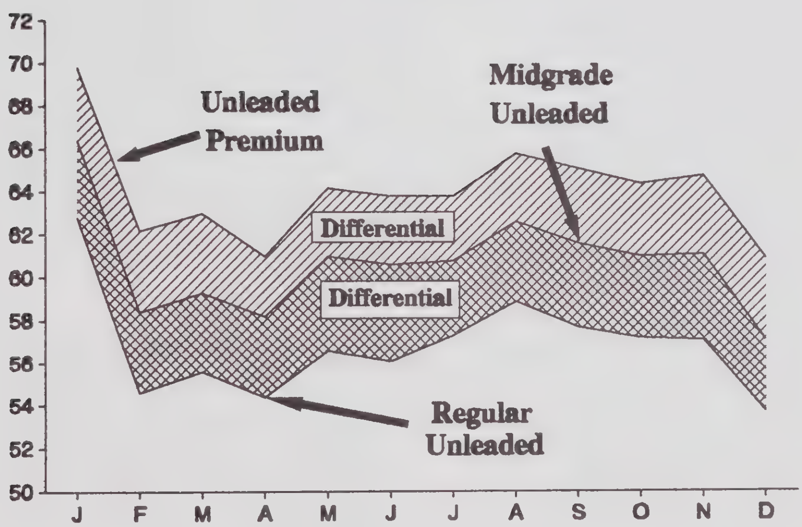
The excise tax component of the federal taxes remained unchanged during the year at 8.5 ¢/litre for gasoline and 4.0 ¢/litre for diesel.

The provincial taxes increased gradually throughout the year, primarily because several provinces, those from Quebec east, chose to include the GST in their provincial tax bases. These provinces have the highest petroleum product prices in Canada, which contribute to higher federal taxes, and, in turn, to higher provincial taxes. The weighted average provincial tax for regular unleaded gasoline, which was 11.4 ¢/litre in December 1990, rose to 13.1 ¢/litre in December 1991. Quebec began collecting an 8% sales tax on petroleum products, effective January 1, 1991, in addition to the provincial road tax. Provincial and territorial budgets also resulted in tax hikes in 1991. The most significant changes were in Quebec and Ontario, where increases totalling 4.5 ¢/litre and 3.4 ¢/litre, respectively, were phased in over the year. In both cases, the last increase became effective on January 1, 1992.

9.5 Price Differentials

In 1991, there was a tendency for the price spreads among the grades of motor gasoline to widen as marketers tried to cover the rising cost of gasoline production (Figure 9.5). The 1990 phase out of lead, combined with recent environmental requirements, have forced refiners to use more costly processes in gasoline production. Widening the price differential allowed retailers to keep regular unleaded prices lower while increasing revenues from sales of the more costly grades.

Figure 9.5
1991 Average Unleaded Motor Gasoline Prices
(At Self-Serve)
cents/litre



By the end of December 1991, the spread among the grades had increased in all but a few centres, with the price differentials tending to be marginally lower in the Maritimes. In December, the price differentials between regular and midgrade unleaded ranged from a low of 1.2 ¢/litre in Charlottetown to a high of 3.3 ¢/litre in Montreal while the spread between regular and premium unleaded ranged from a low of 2.4 ¢/litre in Charlottetown to a high of 6.6 ¢/litre in Montreal. Charlottetown, the only surveyed centre with a regulated market, saw a reduction in its price spreads while all the other centres surveyed incurred increases (as high as 2.9 ¢/litre in Halifax).

9.6 Canada vs United States

The average retail price of motor gasoline showed a greater decline in Canada than in the United States during 1991. Consequently, the difference between the Canadian and American average gasoline price was reduced from 22.4 ¢/litre in December 1990 to 21.3 ¢/litre in November 1991.

Higher Canadian consumption taxes continue to account for more than 70% of the difference between the two countries (Figure 9.6.1).

Figure 9.6.1
Motor Gasoline - Including Taxes
cents/litre

The average full serve/self serve differential in Canada widened by about 0.3 ¢/litre during 1991, while the similar differential in the United States increased by 1.2 ¢/litre. The average full serve/self serve differential in the United States of 8.5 ¢/litre continues to be substantially higher than the Canadian spread of 0.9 ¢/litre.

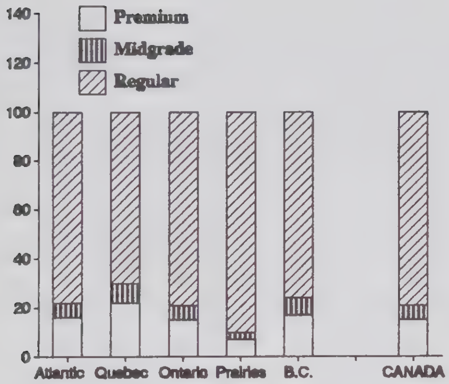
Figure 9.6.2
Motor Gasoline - Excluding Taxes
cents/litre

9.7 Structural Changes

Although the major refiners continued to have the largest share of the retail gasoline market, that share declined in most major Canadian centres in 1991. The regional refiners experienced gains at the Majors' expense, particularly in eastern Canada where Ultramar acquired Texaco's downstream assets. The independent marketers also continued to make gains and accounted for more than 30% of the market in both Winnipeg and Edmonton. In the twelve major centres studied, the Majors accounted for 58% of retail gasoline sales, while regional refiners and independents had 20% and 22%, respectively.

Since its introduction in 1989, midgrade gasoline's share of retail sales had been growing. In 1991, however this growth appears to have levelled off, with midgrade making up just over 5% of total gasoline sales, down marginally from 1990. The recession has contributed to a decline in premium gasoline's market share to 15%, from nearly 18% in 1990, with fewer consumers opting for the higher-priced fuel. Regular unleaded gasoline continues to account for nearly 80%

Figure 9.7
1991 Motor Gasoline Sales
percent



of total sales. The split among the three grades varied significantly from region to region (Figure 9.7). In Quebec, for example, 22% of sales were premium gasoline, while that grade made up only 7% of sales in the Prairie provinces.

On July 11, 1991, the Government of Nova Scotia deregulated the province's petroleum product industry. Prices, barriers to entry, and most other facets of the wholesale and retail levels of the marketing sector will no longer be regulated by the Public Utilities Board but rather will be determined by market forces. Prince Edward Island is now the only province that regulates petroleum product prices.

Octane Rating

In 1991, two motor gasoline retailers, Chevron Canada and Sunoco began posting 'octane ratings' at the pump. Although 'octane 'and 'octane rating' are commonly used technical terms they are most often misunderstood.

A report entitled **"Octane Rating - A Challenge for the Petroleum Industry"** prepared and published by the *Canadian Oil Markets and Emergency Planning Division* in cooperation with the *Petroleum Technology Division* defines 'octane' and 'octane rating' and their significance to the industry and consumer.

For further information concerning this report please contact Loise Desilva (613-992-0602) and Micheal Hnetka (613-992-2916).

10. Financial Performance of the Canadian Oil and Gas Industry in 1991

The following section was prepared by the Petroleum Monitoring and Information Services Division (PMIS) of the Economic and Financial Analysis Branch. Further information is available from V. Stanciulescu (613) 995-2100 and F. Laberge (613) 996-8035.

- Internal cash flow decreased 29% to $5.9 billion in 1991 from $8.3 billion in 1990.
- Net income after unusual items fell $3.9 billion from a profit of $2 billion in 1990 to a loss of $1.9 bllion in 1991.
- Gross capital expenditures increased 12% to $8.1 billion in 1991.
- The reinvestment rate rose to 136% from 86% in 1990 .
- Dividend payments in 1991 decreased 17% to $1.3 billion from $1.5 billion.
- The petroleum industry's rate of return on capital employed for 1991 was a negative 0.5% vs. 4.8% for 1990.
- Long-term debt as a percentage of capital employed increased to 45% from 39% in 1990.

Total sales revenues decreased 10% to $41.3 billion in 1991 from $46 billion recorded in 1990. The decrease was largely the result of a sharp decline in the overall demand for refined products, and the replacement in 1991 of the Federal Sales Tax (FST) with the Goods and Services Tax (GST). While for financial reporting purposes, the FST was included in both revenues and expenses, the GST is excluded from the financial results in accordance with generally accepted accounting principles. Consequently, a discontinuity in revenue levels exists between the two reporting periods.

Lower sales revenues were also due to declining international prices for crude oil, marketable natural gas and gas liquids combined with the greater strength of the Canadian dollar vs. the US dollar (Figure 10.3). The decline in revenues was partly offset by higher production of natural gas and crude oil hedging operations. The latter activity increased in late 1990 during the period of high crude oil prices and played itself out during the first half of 1991.

Figure 10.1 Crude Oil Volumes and Average Prices: 1982 - 1991

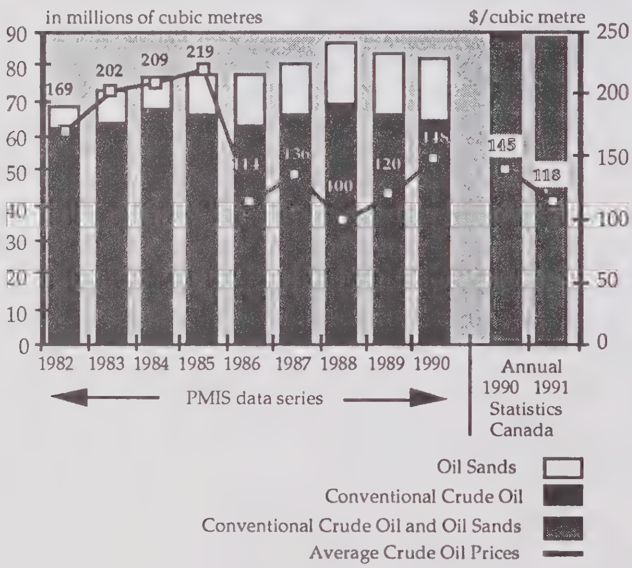
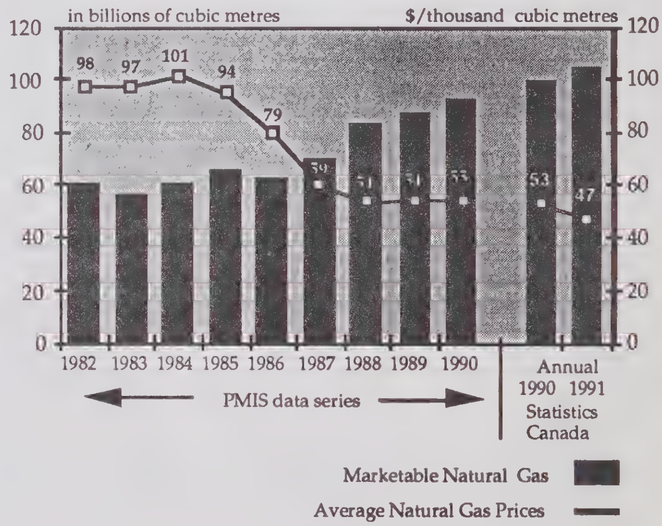
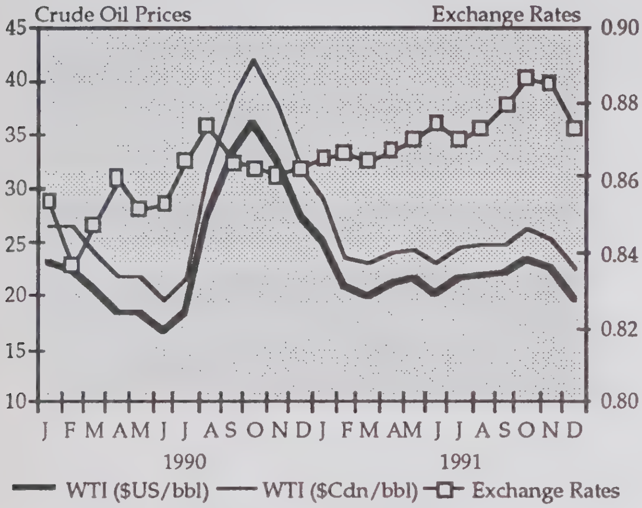


Figure 10.2 Marketable Natural Gas Volumes and Average Prices: 1982 - 1991



Note : Data for figures 10.1 and 10.2 were obtained from monitoring survey results except for the two end bars which are derived from Statistics Canada and EM & R. The monitoring survey covers approximately 90% of the industry, compared with 100% for the other data series.

Figure 10.3 Crude Oil Prices and Exchange Rates



	Annual 1990	1991
Avg. WTI ($US/bbl)	24.49	21.48
Avg. Exchange Rate	0.857	0.873
Avg. Cdn. Prices ($Cdn/bbl)	28.54	24.62

Sources: EMR, Oil and Gas Branch; Bank of Canada

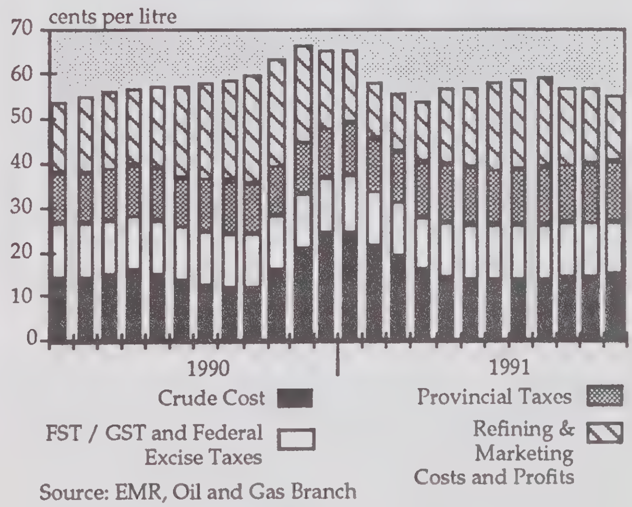
Table 10.1 Overview of Total Industry

	1990	1991	Change	
	---- $ billions	----		(%)
Sales Revenues	46.0	41.3	-4.7	-10
Other Revenues	0.5	0.4	-0.1	-10
Total Operating Expenses	42.8	41.7	-1.1	-3
Other Deductions	-	1.9	1.9	-
All Current Taxes	1.6	0.5	-1.1	-66
Deferred Taxes	0.2	-0.6	-0.8	-
Net Income before Extraordinary Items	**1.8**	**-1.9**	**-3.7**	**-**
Extraordinary and Other Items	0.2	-	-0.2	-
Net Income after Extraordinary Items	**2.0**	**-1.9**	**-3.9**	**-**
Internal Cash Flow	**8.3**	**5.9**	**-2.4**	**-29**

Sales of refined petroleum products fell in 1991 largely due to the economic downturn. Also, fierce competition kept companies from recovering the cost of high priced inventories acquired in late 1990 and early 1991.

Internal cash flow decreased 29% from $8.3 billion in 1990 to $5.9 billion in 1991, the lowest level recorded in the last twelve years. The cash flow decline was caused by a decrease in total revenues of $4.7 billion (10%). 'Other expenses', which includes operating costs, cost of goods sold and royalty payments dropped 3% ($935 million). Cost of goods sold (feedstock costs) was particularly high in 1990 as refiners built up high cost inventories during the second half of the year as a result of the Persian Gulf crisis. However, lower interest payments of $315 million, or 14%, and a drop in current income taxes of $1 billion, or 66%, partly offset the reduction of cash flow (Table 10.7). Despite an increase in long-term debt, interest payments dropped as a result of lower interest rates.

Figure 10.4 Average Retail Price of Motor Gasoline: Monthly, 1990 - 1991

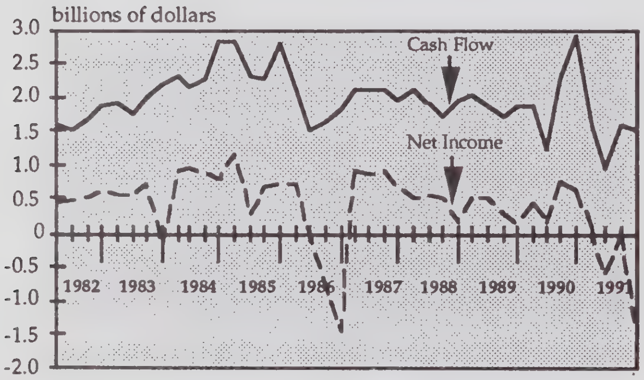


Source: EMR, Oil and Gas Branch

Net income from all Canadian operations of the industry fell $3.9 billion, from a profit of $2 billion in 1990 to a loss of $1.9 billion in 1991. Aside from the factors affecting cash flow, the decline was due to write-downs of $2.4 billion in assets in 1991 vs. write-downs of $815 million in 1990. The write-downs, mainly the result of ceiling tests, were in response to lower marketable natural gas prices. There were also write-downs due to discontinuing operations in both the upstream and downstream segments, and downward valuation of reserves involved in swap arrangements. The poor results were also due to provisions for workforce reduction programs, lower gains on sale of assets, lower equity earnings, and higher depreciation, depletion and amortization. Part of the increase in depletion charges was as a result of the inclusion of accrued costs for future site restoration, following a new CICA accounting recommendation.

Partly offsetting the decline in net income were recoveries of $585 million in deferred taxes compared with $185 million of deferred taxes in 1990. This change was mainly the result of the numerous sale of assets and write-downs which occurred in 1991.

Figure 10.5 Net Income and Cash Flow 1982 - 1991: Quarterly Data



Canadian-controlled companies' cash flow decreased $790 million (24%) to $2.5 billion in 1991 from $3.2 billion in 1990. Cash flow declined due to lower sales revenues caused by lower crude oil and natural gas prices. 'Other expenses', which includes operating and feedstock costs, and royalties, were down $445 million, interest charges were down by $130 million, and current income taxes were lower by $230 million.

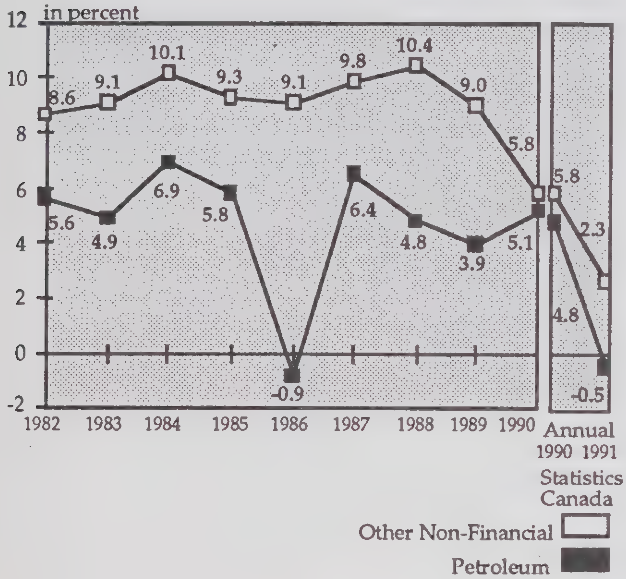
Net income declined $1.5 billion, from a profit of $680 million in 1990 to a loss of $780 million in 1991. Contributing to the decline in net income were higher write-offs of $1 billion in 1991 compared with write-offs of $95 million in 1990.

Foreign-controlled companies' cash flow declined $1.7 billion, or 33%, to $3.4 billion in 1991 from $5.1 billion in 1990. Sales revenues declined to $27.2 billion (down $3.1 billion). 'Other expenses', which includes operating and feedstock costs, and royalty payments, fell $490 million. Interest payments were down $185 million and current income taxes dropped by $810 million.

Net income fell $2.5 billion, from a profit of $1.4 billion in 1990 to a loss of $1.1 billion in 1991. Other than the factors affecting cash flow, the decline in net income was the result of higher write-offs ($1.3 billion in 1991 vs. $720 million in 1990). Higher deferred income tax recoveries of $340 million in 1991 partly offset the decrease in net income.

The petroleum industry's **rate of return on capital employed** for 1991 was a negative 0.5% vs. 4.8% for 1990. The other non-financial industries (excluding petroleum) recorded a rate of return on capital employed of 2.3% for 1991, vs. 5.8% for 1990 (Figure 10.6 and Note).

Figure 10.6 Rates of Return on Capital Employed



Dividend payments by the petroleum industry decreased 17% to $1.3 billion in 1991 from $1.5 billion in 1990. Dividends paid by Canadian-controlled companies declined 10% to $425 million, while dividend payments by foreign-controlled companies dropped 21% to $830 million.

Table 10.2 Dividend Payments

	1990	1991	Per Cent of Net Income(a) 1990	1991
	- -$ millions - -		(%)	
Canadian-Controlled	472	426	70	n/a
Foreign-Controlled	1047	832	77	n/a
Total Industry	1519	1258	75	n/a

(a) Percentages are derived by dividing dividend payments by net income.

Overall gross capital expenditures for the petroleum industry increased 12% ($870 million) to $8.1 billion in 1991. Net of grants, incentives and contributions, capital expenditures rose 11% to $8 billion. Higher capital expenditures were the result of outlays on major projects, such as the Caroline gas field development, the Bi-Provincial heavy oil upgrader and the Hibernia project.

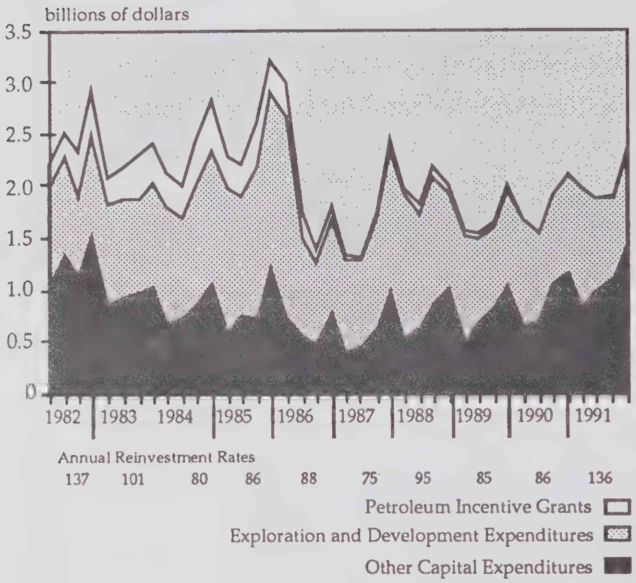
Table 10.3 Capital Expenditures and Reinvestment Rates

	1990	1991	Change	
	-- $ billions --			(%)
Gross Capital Expenditures	7.2	8.1	0.9	12
Less: Incentive, Grants and Contributions	*	0.1	0.1	-
Net Capital Expenditures	7.2	8.0	0.8	11
Reinvestment Rate: Net Capital Expenditures as a Per Cent of Cash Flow	86%	136%		

* Less than $50 million.

Exploration and development spending rose 2% to $3.7 billion in 1991, while other capital expenditures on new construction, buildings, machinery and equipment, increased 22% to $4.4 billion. Gross capital outlays for Canadian-controlled companies rose 11% to $3.7 billion, while those of foreign-controlled companies increased 13% to $4.4 billion (Table 10.5).

Figure 10.7 Capital Expenditures and Reinvestment Rates: 1982 - 1991



The total reinvestment rate increased to 136% in 1991 from 86% in 1990 (Table 10.4). The reinvestment rate for Integrateds and Refiners increased to 158% from 77%, while the rate for the Oil and Gas Producers group rose to 125% from 93%.

Table 10.4 Total Capital Expenditures (Net Of Incentive Grants) as a Per Cent of Internal Cash Flow

	1990	1991
	(%)	
Integrateds and Refiners	77	158
Canadian-Controlled	104	196
Foreign-Controlled	70	150
Senior Oil and Gas Producers	87	121
Canadian-Controlled	96	132
Foreign-Controlled	76	106
Junior Oil and Gas Producers	119	142
Canadian-Controlled	118	161
Foreign-Controlled	120	124
Oil and Gas Producers	93	125
Canadian-Controlled	100	138
Foreign-Controlled	86	110
Total Industry	**86**	**136**
Canadian-Controlled	101	146
Foreign-Controlled	77	129

Debt[1] to Equity Analysis:

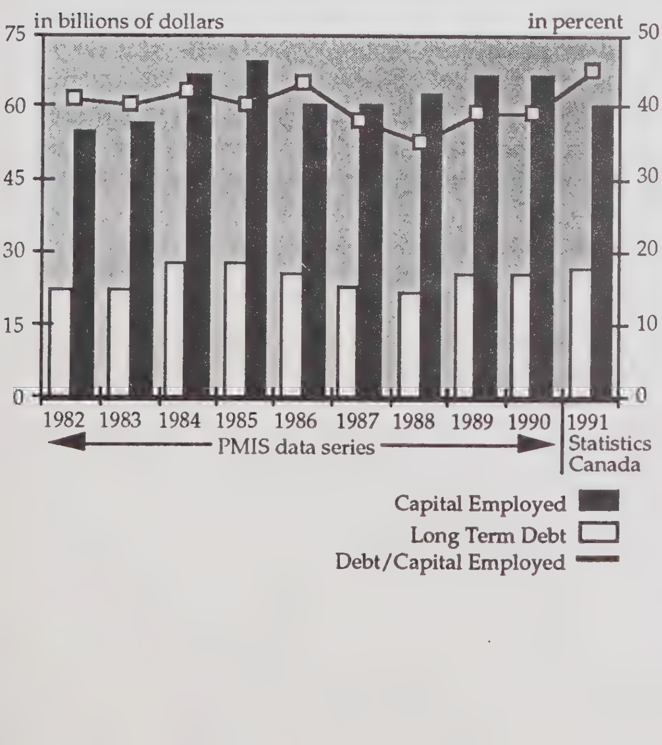
Industry's total debt in 1991 rose $2.3 billion to $27 billion from $24.7 billion in 1990 largely as a result of higher 'Other long-term liabilities'. Canadian-controlled companies' debt rose $1.4 billion (14%) mainly as the result of long-term borrowing by one company and the subsequent investment of the borrowed money in short-term, fixed-income investments. Also, long-term debt rose following financial and operational reorganizations, and the spin-off of a petroleum company which assumed the long-term debt previously held by the parent company.

The foreign-controlled group increased their debt by 7% ($1 billion), mainly to fund higher spending on major capital projects (Table 10.9). For both groups of companies the 'Other long-term liabilities' account rose in 1991 following the adoption of the new CICA recommendations to accrue and recognize future site restoration costs. The increase in debt was somewhat moderated by companies paying back debt, following sales of assets or floating new equity.

During the same period total shareholders' equity declined $4.5 billion (12%) to $33.5 billion. While common and preferred share capital declined marginally ($365 million, or 2%) as redemption of shares slightly exceeded new issues, retained earnings registered a large drop of $3.7 billion (25%). Aside from the net loss for the year of $1.9 billion, special charges were taken against this account to reflect changes in accounting policies. For a number of companies, the adoption of the new CICA recommendation for future site restoration costs together with changes in the method of inventory valuation resulted in unusual charges that affected current and prior year results. Furthermore, the decline in equity was the result of restructuring activity by a number of companies, as contributed surplus and preferred shares were converted to common share capital and short-term liabilities.

(1) Debt includes long-term debt and other long-term liabilities.

Figure 10.8 Debt(1) to Capital Employed



As a result of the above changes in debt and equity, the ratio of debt(1) to capital employed (defined as long-term debt, other long-term liabilities and equity) increased to 45% in 1991 from 39% in 1990 (Figure 10.8).

Fourth Quarter 1991:

Net Income for the fourth quarter of 1991 fell $2.2 billion from a profit of $635 million in 1990 to a loss of $1.5 billion in 1991 (Table 10.8). The decrease was primarily due to lower sales revenues, (down $3.3 billion, or 24%), higher write-offs (up $1.2 billion), and extraordinary losses in the fourth quarter of 1991 vs. equity gains in 1990. Also, 'Other expenses' declined $1.4 billion, or 15%. Partly offsetting the lower revenues and higher write-offs were lower current income taxes (down $470 million, or 87%) and deferred income tax recoveries of $490 million in 1991. Internal cash flow decreased 46% to $1.5 billion from $2.9 billion.

Overall capital expenditures in the fourth quarter of 1991 increased 10% to $2.3 billion. Exploration and development spending fell 7% to $880 million, while other capital expenditures increased 23% to $1.4 billion (Table 10.6). The increase in the latter category was due to the acquisition of new buildings, machinery and equipment for major projects.

Note : This report was prepared from quarterly data obtained from individual companies via Statistics Canada. In contrast to the semi-annual monitoring survey, the report covers the combined results of upstream, downstream and other Canadian operations but excludes the results of Canadian companies' foreign activities. In addition, this report contains about 40 fewer companies, mostly small or government owned. Nonetheless, the information contained in this analysis gives a reliable overview of the industry's financial performance for 1991.

March 1992

Table 10.5

Capital Expenditures of Petroleum Industry
Annual

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1990	1991	Change %	1990	1991	Change %	1990	1991	Change %
	$ millions			$ millions			$ millions		
Exploration and Development (E&D)									
E&D Expensed (1)									
Land & Lease Acquisition and Retention	82	90	10	12	9	-25	70	81	16
Drilling Expenditures	401	459	14	163	163	0	238	295	24
Geological and Geophysical	334	250	-25	54	27	-50	281	223	-21
Total E&D Expensed	817	799	-2	229	199	-13	589	599	2
E&D Capitalized									
Land & Lease Acquisition and Retention	690	536	-22	349	236	-32	341	300	-12
Drilling Expenditures	1838	2052	12	1085	1236	14	752	816	9
Geological and Geophysical	313	344	10	205	218	6	108	126	17
Total E&D Capitalized	2841	2932	3	1639	1690	3	1201	1242	3
Total Exploration and Development	**3658**	**3731**	**2**	**1868**	**1889**	-	**1790**	**1841**	**3**
Other Capitalized Expenditures									
Mining	72	56	-22	24	26	8	49	30	-39
New Const., Build., Mach., and Equip.	2901	3711	28	1309	1531	17	1592	2180	37
Used Build., Mach., Equip., & Land	380	390	3	22	130	-	357	260	-27
Other Capital Expenditures	223	218	-2	77	87	13	145	132	-9
Total Other Capital Expenditures	3576	4375	22	1432	1774	24	2143	2602	21
Total Capital Expenditures	**7234**	**8106**	**12**	**3300**	**3663**	**11**	**3933**	**4443**	**13**
Capital Grants	39	100	156	24	65	171	15	35	133
Net Capital Expenditures	**7195**	**8006**	**11**	**3276**	**3598**	**10**	**3918**	**4408**	**13**

(1) Excludes mining expenditures.

Table 10.6

Capital Expenditures of Petroleum Industry
Fourth Quarter

	Total Industry 1990	Total Industry 1991	Total Industry Change %	Canadian-Controlled 1990	Canadian-Controlled 1991	Canadian-Controlled Change %	Foreign-Controlled 1990	Foreign-Controlled 1991	Foreign-Controlled Change %
	$ millions			$ millions			$ millions		
Exploration and Development (E&D)									
E&D Expensed (1)									
Land & Lease Acquisition and Retention	20	24	24	3	2	-25	17	22	33
Drilling Expenditures	136	136	-	27	47	74	110	89	-19
Geological and Geophysical	94	61	-35	26	10	-62	68	50	-26
Total E&D Expensed	250	221	-12	56	59	5	195	161	-17
E&D Capitalized									
Land & Lease Acquisition and Retention	146	100	-32	69	42	-39	77	59	-23
Drilling Expenditures	458	469	2	240	318	33	218	151	-31
Geological and Geophysical	86	89	3	55	66	20	31	23	-26
Total E&D Capitalized	690	658	-5	364	426	17	326	233	-29
Total Exploration and Development	**940**	**879**	**-6**	**420**	**485**	**15**	**521**	**394**	**-24**
Other Capitalized Expenditures									
Mining	18	7	-61	1	-	-83	17	7	-59
New Const., Build., Mach., and Equip.	847	1131	34	402	450	12	445	682	53
Used Build., Mach., Equip., & Land	215	224	4	5	114	-	210	110	-48
Other Capital Expenditures	75	59	-21	24	20	-17	52	39	-25
Total Other Capital Expenditures	1155	1421	23	432	584	35	724	838	16
Total Capital Expenditures	**2095**	**2300**	**10**	**852**	**1069**	**25**	**1245**	**1232**	**-1**
Capital Grants	10	46	-	10	29	190	-	17	-
Net Capital Expenditures	**2085**	**2254**	**8**	**842**	**1040**	**24**	**1245**	**1215**	**-2**

(1) Excludes mining expenditures.

Table 10.7

Income Statement
Annual

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1990	1991	Change %	1990	1991	Change %	1990	1991	Change %
	$ millions			$ millions			$ millions		
Sales Revenues	**45960**	**41260**	**-10**	**15589**	**14011**	**-10**	**30372**	**27249**	**-10**
Other Revenues									
Interest from Canadian Sources	402	351	-13	179	173	-4	222	178	-20
Dividends from Canadian Corporations	55	63	13	42	31	-27	13	32	137
Foreign Dividends and Interest Revenues	18	13	-28	0	3	-	18	10	-41
Total Revenues	**46435**	**41686**	**-10**	**15810**	**14215**	**-10**	**30625**	**27468**	**-10**
Expenses									
E & D Expensed	842	821	-2	231	201	-13	611	621	2
D, D & A Charges	5390	5648	5	2184	2354	8	3206	3294	3
Other Expenses	34208	33275	-3	11072	10629	-4	23136	22646	-2
Interest Expenses	2319	2004	-14	1108	979	-12	1211	1026	-15
Total Operating Expenses	**42758**	**41748**	**-2**	**14595**	**14163**	**-3**	**28163**	**27586**	**-2**
Other Transactions									
Gains on Translation of Currency	174	107	-39	-5	-9	-	179	116	-35
Gains on Sale of Assets	562	418	-26	58	192	-	504	226	-55
Write-offs and Valuation Adjustments	-815	-2381	-	-93	-1038	-	-722	-1344	-
Income before Income Taxes	**3598**	**-1919**	**-**	**1175**	**-801**	**-**	**2423**	**-1119**	**-**
Income Taxes									
Current	1567	526	-66	380	149	-61	1187	378	-68
Deferred (tax allocation method)	187	-586	-	201	-231	-215	-14	-356	-
Net Income after income taxes	**1843**	**-1859**	**-**	**593**	**-719**	**-**	**1250**	**-1141**	**-**
Other Income									
Equity Income	188	-2	-	86	-31	-	102	30	-71
Extraordinary Items	-	-65	-	-	-28	-	-	-36	-
Net income after Extraordinary Items	**2031**	**-1927**	**-**	**679**	**-779**	**-**	**1353**	**-1148**	**-**
Cash Flow	**8339**	**5880**	**-29**	**3249**	**2461**	**-24**	**5091**	**3419**	**-33**

	Integrateds and Refiners			Oil and Gas Producers		
	1990	1991	Change %	1990	1991	Change %
	$ millions			$ millions		
Sales Revenues	**29787**	**26257**	**-12**	**16173**	**15003**	**-7**
Other Revenues						
Interest from Canadian Sources	181	136	-25	221	215	-3
Dividends from Canadian Corporations	9	17	100	47	46	-3
Foreign Dividends and Interest Revenues	1	1	86	17	12	-33
Total Revenues	**29977**	**26410**	**-12**	**16458**	**15275**	**-7**
Expenses						
E & D Expensed	252	272	8	589	550	-7
D, D & A Charges	2121	2204	4	3269	3444	5
Other Expenses	24359	23440	-4	9849	9834	-
Interest Expenses	1036	837	-19	1283	1167	-9
Total Operating Expenses	**27768**	**26753**	**-4**	**14990**	**14996**	**-**
Other Transactions						
Gains on Translation of Currency	58	34	-41	116	73	-38
Gains on Sale of Assets	463	247	-47	99	171	73
Write-offs and Valuation Adjustments	-625	-1369	-	-189	-1012	-
Income before Income Taxes	**2104**	**-1430**	**-**	**1494**	**-489**	**-**
Income Taxes						
Current	1022	161	-84	545	366	-33
Deferred (tax allocation method)	-144	-553	-	331	-34	-
Net Income after income taxes	**1227**	**-1038**	**-**	**616**	**-821**	**-**
Other Income						
Equity Income	23	2	-91	165	-4	-
Extraordinary Items	-	-	-	-	-65	-
Net income after Extraordinary Items	**1250**	**-1036**	**-**	**781**	**-891**	**-**
Cash Flow	**3560**	**1973**	**-45**	**4779**	**3907**	**-18**

Table 10.8

Income Statement
Fourth Quarter

	Total Industry 1990	Total Industry 1991	Change %	Canadian-Controlled 1990	Canadian-Controlled 1991	Change %	Foreign-Controlled 1990	Foreign-Controlled 1991	Change %
	$ millions			$ millions			$ millions		
Sales Revenues	13530	10220	-24	4638	3559	-23	8892	6661	-25
Other Revenues									
Interest from Canadian Sources	102	102	-	37	47	27	65	55	-16
Dividends from Canadian Corporations	14	14	2	11	5	-52	3	9	-
Foreign Dividends and Interest Revenues	6	5	-20	-	1	-	6	3	-45
Total Revenues	13652	10341	-24	4686	3611	-23	8966	6728	-25
Expenses									
E & D Expensed	255	226	-11	56	59	5	199	167	-16
D, D & A Charges	1447	1553	7	575	670	16	872	883	1
Other Expenses	9647	8199	-15	3143	2664	-15	6504	5535	-15
Interest Expenses	595	522	-12	288	251	-13	307	271	-12
Total Operating Expenses	11944	10500	-12	4062	3644	-10	7881	6855	-13
Other Transactions									
Gains on Translation of Currency	52	11	-79	-1	-1	-	53	12	-78
Gains on Sale of Assets	62	151	145	25	51	102	36	100	176
Write-offs and Valuation Adjustments	-670	-1895	-	-1	-796	-	-670	-1100	-
Income before Income Taxes	1151	-1892	-	647	-777	-	504	-1115	-
Income Taxes									
Current	538	71	-87	154	76	-51	385	-5	-
Deferred (tax allocation method)	-	-492	-	108	-341	-	-108	-151	-
Net Income after income taxes	613	-1471	-	386	-513	-	228	-959	-
Other Income									
Equity Income	11	-22	-	12	-48	-	-5	36	-
Extraordinary Items	-	-31	-	-	-28	-	-	-3	-
Net income after Extraordinary Items	635	-1525	-	397	-590	-	238	-935	-
Cash Flow	2872	1549	-46	1101	621	-44	1771	928	-48

	Integrateds and Refiners 1990	Integrateds and Refiners 1991	Change %	Oil and Gas Producers 1990	Oil and Gas Producers 1991	Change %
	$ millions			$ millions		
Sales Revenues	8620	6404	-26	4910	3816	-22
Other Revenues						
Interest from Canadian Sources	45	48	6	56	53	-5
Dividends from Canadian Corporations	2	6	-	13	9	-30
Foreign Dividends and Interest Revenues	1	1	-	5	3	-35
Total Revenues	8667	6458	-25	4984	3882	-22
Expenses						
E & D Expensed	61	73	20	194	153	-21
D, D & A Charges	541	606	12	906	947	5
Other Expenses	6782	5701	-16	2865	2498	-13
Interest Expenses	262	205	-22	333	317	-5
Total Operating Expenses	7646	6585	-14	4298	3915	-9
Other Transactions						
Gains on Translation of Currency	14	9	-37	38	2	-95
Gains on Sale of Assets	31	135	-	30	17	-45
Write-offs and Valuation Adjustments	-591	-1098	-	-79	-797	-
Income before Income Taxes	476	-1080	-	675	-812	-
Income Taxes						
Current	404	58	-86	134	13	-90
Deferred (tax allocation method)	-232	-414	-	232	-78	-
Net Income after income taxes	304	-724	-	309	-747	-
Other Income						
Equity Income	-6	4	-	18	-27	-
Extraordinary Items	-	-	-	-	-31	-
Net income after Extraordinary Items	299	-720	-	336	-805	-
Cash Flow	1219	495	-59	1653	1054	-36

Table 10.9
Balance Sheet

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	Dec. 31 1990	Dec. 31 1991	Change %	Dec. 31 1990	Dec. 31 1991	Change %	Dec. 31 1990	Dec. 31 1991	Change %
	$ millions			$ millions			$ millions		
Cash, Investments and Marketable Securities	845	476	-44	363	233	-36	483	243	-50
Accounts Receivable:									
Trade (include affiliates)	6571	5495	-16	2279	1998	-12	4292	3498	-19
All Other	475	699	47	319	334	5	156	365	134
Total	7046	6194	-12	2598	2332	-10	4448	3862	-13
Inventories	5464	3441	-37	1589	1144	-28	3875	2298	-41
Other Current Assets	829	1973	138	329	1095	233	499	877	76
Total Current Assets	**14184**	**12084**	**-15**	**4879**	**4804**	**-2**	**9305**	**7280**	**-22**
Net Fixed and Depletable Assets	62815	60464	-4	26220	25388	-3	36595	35076	-4
Other Long-term Assets	8238	7484	-9	4580	4035	-12	3658	3449	-6
Total Assets	**85237**	**80032**	**-6**	**35679**	**34227**	**-4**	**49558**	**45805**	**-8**
Accounts payable:									
Trade (include affiliates)	5582	4469	-20	2407	1785	-26	3175	2684	-15
All Other	1610	2047	27	308	589	91	1302	1458	12
Total	7192	6515	-9	2714	2373	-13	4477	4142	-7
Other Current Liabilities	4387	3006	-31	1873	1264	-33	2514	1742	-31
Total Current Liabilities	**11579**	**9521**	**-18**	**4587**	**3637**	**-21**	**6991**	**5884**	**-16**
Long-term Debt	22156	23319	5	9013	9692	8	13143	13627	4
Accumulated Deferred Income Taxes	10995	10015	-9	4338	4072	-6	6657	5943	-11
Other Long-term Liabilities	2514	3728	48	820	1513	85	1692	2213	31
Shareholders' Equity									
Common	14379	14273	-1	7810	8276	6	6569	5997	-9
Preferred	3441	3182	-8	2034	1564	-23	1408	1618	15
Retained earnings	15077	11407	-24	3661	2520	-31	11417	8888	-22
Contributed surplus	5096	4587	-10	3416	2953	-14	1681	1635	-3
Total Liabilities, Deferred Taxes and Equity	**85237**	**80032**	**-6**	**35679**	**34227**	**-4**	**49558**	**45805**	**-8**
Working Capital	**2605**	**2563**	**-2**	**292**	**1167**	**-**	**2314**	**1396**	**-40**

	Integrateds and Refiners			Oil and Gas Producers		
	Dec. 31 1990	Dec. 31 1991	Change %	Dec. 31 1990	Dec. 31 1991	Change %
	$ millions			$ millions		
Cash, Investments and Marketable Securities	149	62	-59	696	414	-40
Accounts Receivable:						
Trade (include affiliates)	3970	3157	-20	2601	2339	-10
All Other	152	402	165	323	297	-8
Total	4122	3559	-14	2924	2636	-10
Inventories	4821	2878	-40	643	564	-12
Other Current Assets	237	667	-	591	1304	-
Total Current Assets	**9329**	**7166**	**-23**	**4854**	**4918**	**1**
Net Fixed and Depletable Assets	27817	26798	-4	34999	33666	-4
Other Long-term Assets	2472	2214	-10	5766	5270	-9
Total Assets	**39618**	**36178**	**-9**	**45619**	**43854**	**-4**
Accounts payable:						
Trade (include affiliates)	3238	2594	-20	2344	1875	-20
All Other	1022	1115	9	588	932	59
Total	4260	3709	-13	2932	2806	-4
Other Current Liabilities	2790	1587	-43	1596	1419	-11
Total Current Liabilities	**7050**	**5296**	**-25**	**4528**	**4225**	**-7**
Long-term Debt	8454	8591	2	13702	14728	7
Accumulated Deferred Income Taxes	5514	4592	-17	5481	5424	-1
Other Long-term Liabilities	730	1371	88	1783	2355	32
Shareholders' Equity						
Common	5066	5584	10	9313	8689	-7
Preferred	15	366	-	3427	2816	-18
Retained earnings	9734	7469	-23	5343	3939	-26
Contributed surplus	3055	2909	-5	2042	1678	-18
Total Liabilities, Deferred Taxes and Equity	**39618**	**36178**	**-9**	**45619**	**43854**	**-4**
Working Capital	**2279**	**1870**	**-18**	**326**	**693**	**-**

PMIS, March 1992

Appendix I
Production of Canadian Crude Oil and Equivalent

	1990 4Q	1990 Year	1991 1Q	1991 2Q	1991 3Q	1991 4Q	1991 Year
	(000 m³/d)						
A. Light and Equivalent							
Conventional							
Alberta	116.6	116.8	117.0	111.3	111.9	115.7	114.0
B.C.	5.4	5.3	5.5	5.3	5.4	5.3	5.3
Saskatchewan	12.4	11.7	11.4	10.9	10.8	11.0	11.1
Manitoba	2.0	2.0	2.0	1.9	1.9	2.0	1.9
Ontario	0.6	0.6	0.6	0.7	0.6	0.6	0.6
Other	5.2	5.0	5.3	5.2	5.2	5.2	5.3
Total	**142.2**	**141.4**	**141.8**	**135.3**	**135.8**	**139.8**	**138.2**
Synthetic							
Suncor	10.3	8.2	9.7	10.0	9.0	8.4	9.3
Syncrude	27.2	24.6	22.3	22.8	27.5	29.5	25.6
Total	**37.5**	**32.8**	**32.0**	**32.8**	**36.5**	**37.9**	**34.9**
Pentanes Plus*	**6.7**	**6.4**	**6.6**	**6.8**	**5.5**	**7.2**	**6.5**
Total Light	**186.4**	**180.6**	**180.4**	**174.9**	**177.8**	**184.9**	**179.6**
B. Heavy Crude							
Alberta							
Conventional	29.0	28.3	29.0	28.7	28.3	28.3	28.6
Bitumen	22.9	21.5	21.2	18.8	14.9	16.6	17.9
Diluent	10.0	9.1	9.9	8.1	9.2	8.5	8.9
Total	**61.9**	**58.9**	**60.1**	**55.6**	**52.4**	**53.4**	**55.4**
Saskatchewan							
Conventional	21.5	21.5	22.3	21.1	22.1	22.3	21.9
Diluent	2.8	2.8	3.4	2.8	2.9	2.9	3.0
Total	**24.3**	**24.3**	**25.7**	**23.9**	**25.0**	**25.2**	**24.9**
Total Heavy	**86.2**	**83.2**	**85.8**	**79.5**	**77.4**	**78.6**	**80.3**
C. Production	**272.6**	**263.8**	**266.2**	**254.7**	**255.2**	**263.5**	**259.9**

* *excludes diluent*

Appendix II
Supply and Disposition of Canadian Crude Oil and Equivalent

	4Q	1990 Year	1Q	2Q	3Q	4Q	1991 Year
				(000 m³/d)			
A. Light and Equivalent							
Supply							
Production	186.4	180.7	180.3	174.8	177.8	184.9	179.5
Newgrade	2.4	1.4	1.6	1.0	2.2	3.3	2.0
Draw/(Build)	3.5	3.8	8.4	8.4	6.5	0	7.5
Net Supply	192.3	185.9	190.3	184.2	186.5	194.8	189.0
Domestic Demand							
Atlantic	0	0	0	0	0	0	0
Quebec	4.1	8.1	4.9	3.2	2.6	0	2.7
Ontario	70.0	64.7	56.6	56.2	59.6	63.0	58.8
Prairies	51.6	50.2	45.1	46.0	47.9	47.8	46.6
B.C.	18.5	18.1	18.1	16.5	20.3	20.4	18.9
Total	**144.3**	**141.1**	**124.7**	**121.9**	**130.3**	**131.1**	**127.0**
Exports	48.0	44.8	65.6	62.3	56.2	63.7	62.0
Total Demand	**192.3**	**185.9**	**190.3**	**184.2**	**186.5**	**194.8**	**189.0**
B. Heavy Crude (Blended)							
Supply							
Production	86.2	83.2	85.8	79.5	77.3	78.6	80.3
Recycled Diluent	0.8	1.0	0.7	1.3	1.5	0.9	1.1
Draw/(Build)	(2.7)	(0.7)	(1.7)	(3.5)	3.4	0.6	(0.3)
Net Supply	84.3	83.5	84.8	77.3	82.2	80.1	81.1
Domestic Demand							
Atlantic	0.2	0.4	0	0	0	0	0
Quebec	1.2	3.8	0	0	0	0.1	0.1
Ontario	10.2	8.7	9.1	11.4	10.9	9.3	10.2
Prairies	10.4	10.8	9.1	6.7	14.4	10.7	10.3
B.C.	0.8	0.4	0.5	0.5	0.7	0.7	0.6
Total	**22.8**	**24.1**	**18.8**	**18.7**	**25.9**	**20.8**	**21.1**
Exports (* derived)	**61.4**	**59.4**	**66.1**	**58.6**	**56.3**	**59.4**	**60.0**
Total Demand	**84.2**	**83.5**	**84.9**	**77.3**	**82.2**	**80.2**	**81.1**

Appendix III
Crude Oil Exports by Destination

U.S. PAD* Districts		1990 4Q	1990 Year	1991 1Q	1991 2Q	1991 3Q	1991 4Q	1991 Year
		(000 m³/d)						
PADD I	Light	7.0	7.3	6.5				
	Heavy	1.2	1.3	1.7				
	Total	**8.2**	**8.6**	**8.2**				
PADD II	Light	31.2	27.0	47.2				
	Heavy	54.2	51.9	55.5				
	Total	**85.4**	**78.9**	**102.7**				
PADD III	Light	0	0	0		(Data not available)		
	Heavy	0.6	1.3	3.1				
	Total	**0.6**	**1.3**	**3.1**				
PADD IV	Light	9.4	10.7					
	Heavy	3.4	3.0	2.9				
	Total	**12.2**	**12.4**	**12.3**				
PADD V	Light	0.4	0.7	1.3				
	Heavy	1.1	0.9	0.4				
	Total	**1.5**	**1.6**	**1.7**				
U.S.	**Light**	**47.4**	**44.4**	**64.4**				
	Heavy	**60.5**	**58.4**	**63.6**				
	Total	**107.9**	**102.8**	**128.0**				
Offshore	Light	0	0.1	0.8				
	Heavy	1.6	1.2	2.3				
	Total	**1.6**	**1.3**	**3.1**				
Total	**Light**	**47.4**	**44.5**	**65.2**	**62.3**	**56.2**	**63.7**	**62.0**
	Heavy	**62.1**	**59.6**	**65.9**	**58.6**	**56.3**	**59.4**	**60.0**
	Total	**109.5**	**104.1**	**131.1**	**120.9**	**112.5**	**123.1**	**122.0**

* *U.S. Petroleum Administration for Defense (PAD) Districts*

Appendix IV
Pipeline Deliveries

		4Q 1990	1990 Year	1Q	2Q	3Q	4Q	1991 Year
		(000 m³/d)						
A.	**Trans Mountain Pipe Line (TMPL)**							
	Domestic Deliveries							
	Light Crude	14.9	14.6	14.5	14.1	18.7	19.7	16.8
	Heavy Crude	0.3	0.3	0.4	0.2	1.1	0.3	0.5
	Semi Refined Poducts	5.3	5.3	5.5	3.7	3.2	3.2	3.9
	Refined Products	2.7	2.6	2.4	2.0	2.7	2.9	2.5
	Total	**23.3**	**22.8**	**22.8**	**20.0**	**25.7**	26.1	23.7
	Foreign Deliveries							
	Tankers	4.7	3.0	5.7	2.2	3.5	4.5	4.0
	Puget Sound Area	0.7	0.8	1.1	1.6	1.0	0.8	1.1
	Total	**5.4**	**3.8**	**6.8**	**3.8**	**4.5**	**5.3**	**5.1**
	Total TMPL	**28.7**	**26.6**	**29.6**	**23.8**	**30.2**	**31.4**	**28.8**
B.	**Interprovincial Pipe Line (IPL)**							
	Domestic Deliveries							
	Light Crude	85.0	84.1	74.2	74.8	73.1	74.3	74.1
	Heavy Crude	14.4	17.4	12.3	12.3	16.0	14.5	13.8
	Other(1)	30.1	29.7	28.6	26.5	25.4	28.1	27.2
	Total	**129.5**	**131.2**	**115.1**	**113.6**	**114.5**	**116.9**	**115.1**
	Foreign Deliveries(2)							
	Light Crude	38.2	34.6	54.2	49.6	42.6	51.4	49.5
	Heavy Crude	55.1	53.2	57.6	55.3	49.5	50.6	53.2
	Other(1)	6.1	7.1	6.8	7.8	5.6	7.0	6.7
	Total	**99.4**	**94.9**	**118.6**	**112.7**	**97.7**	**109.0**	**109.4**
	Total IPL	**228.9**	**226.1**	**233.7**	**226.1**	**212.2**	**225.9**	**224.5**
C.	**Pipeline to Montreal**							
	IPL Deliveries							
	To Montreal	5.1	12.3	4.9	4.2	1.0	0	2.4
	For Export/Transfer	0	1.2	0	0	0	0	0
	Total IPL	**5.1**	**13.5**	**4.9**	**4.2**	**1.0**	**0**	**2.4**
	Portland-Montreal							
	Montreal Imports(3)	24.2	16.7	24.2	22.4	24.4	29.1	25.0
	Total Mtl Receipts	**30.0**	**29.0**	**29.1**	**26.6**	**25.4**	**29.1**	**27.4**

Note (1): includes petroleum products and NGL's.
(2): includes US domestic crudes delivered to the U.S.
(3): includes cargo imported directly into Montreal.

Appendix V
Canadian Refinery Receipts

	4Q 1990	1990 Year	1Q	2Q	3Q	4Q	1991 Year
	-----	-----	-----	(000 m³/d)	-----	-----	-----
A. Domestic Receipts							
Light & Equivalent							
Atlantic	0	0	0	0	0	0	0
Quebec	4.1	8.1	4.9	3.1	2.6	0	0
Ontario	70.0	64.7	56.6	56.2	59.6	63.0	58.9
Prairies	51.6	50.2	45.1	46.0	47.9	47.7	46.7
B.C.	18.5	18.1	18.1	16.5	20.3	20.4	18.8
Total	**144.2**	**141.1**	**124.7**	**121.8**	**130.4**	**131.1**	**127.0**
Heavy							
Atlantic	0.2	0.4	0	0	0	0	0
Quebec	1.2	3.9	0	0	0	0.1	0
Ontario	10.2	8.6	9.1	11.4	10.9	9.3	10.2
Prairies	10.4	10.9	9.0	6.7	14.4	10.6	10.2
B.C.	0.8	0.4	0.6	0.5	0.7	0.7	0.6
Total	**22.8**	**24.2**	**18.7**	**18.6**	**26.0**	**20.7**	**21.0**
Other Receipts*							
Atlantic	0	0.3	0	1.2	0.2	0	0.3
Quebec	0.5	0.9	0	0.2	0	0	0.1
Ontario	3.7	3.4	3.4	5.3	4.6	4.8	4.5
Prairies	3.7	3.2	3.6	6.1	3.6	2.3	3.9
B.C.	5.4	5.4	5.5	4.0	3.5	3.5	4.1
Total	**13.3**	**13.2**	**12.5**	**16.8**	**11.9**	**10.6**	**12.9**
Total Domestic Receipts							
Atlantic	0.2	0.7	0	1.2	0.2	0	0.3
Quebec	5.8	12.9	4.9	3.3	2.6	0.1	2.7
Ontario	83.9	76.7	69.1	72.9	75.1	77.1	73.6
Prairies	65.7	64.3	57.7	58.8	65.9	60.6	60.8
B.C.	24.7	23.9	24.2	21.0	24.5	24.1	23.5
Total	**180.3**	**178.5**	**155.9**	**157.2**	**168.3**	**162.4**	**160.9**
B. Crude Oil Imports							
Atlantic	47.7	48.4	50.7	37.6	56.3	54.2	49.7
Quebec	43.1	35.1	39.6	35.7	44.2	47.8	41.9
Ontario	1.5	2.8	0.6	0.4	0.5	0.1	0.4
Prairies	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	0	0
Total	**92.3**	**86.3**	**90.9**	**73.7**	**101.0**	**102.1**	**92.0**
C. Total Receipts*							
Atlantic	47.9	49.1	50.7	38.8	56.5	54.2	50.0
Quebec	48.9	48.0	44.5	39.0	46.8	47.9	44.6
Ontario	85.4	79.5	69.7	73.3	75.6	77.2	74.0
Prairies	65.7	64.3	57.7	58.8	65.9	60.6	60.8
B.C.	24.7	23.9	24.2	21.0	24.5	24.6	3.5
Total	**272.6**	**264.8**	**246.8**	**230.9**	**269.3**	**264.5**	**252.9**

* *partially processed oil, gas plant butanes etc.*

Appendix VI
International and Domestic Crude Oil Prices
(US$/bbl)

			Canadian Par	WTI NYMEX	Brent
A.	At Source				
	1990	4Q	30.94	32.08	32.66
		Ave	23.73	24.49	23.87
	1991	1Q	20.72	21.81	20.95
		2Q	19.73	20.77	18.94
		3Q	20.52	21.65	19.90
		4Q	20.63	21.77	20.59
		Ave	20.40	21.50	20.09

			Canadian Par	WTI NYMEX	Brent
B.	At Chicago				
	1990	4Q	32.25	32.67	34.54
		Ave	25.00	25.09	25.70
	1991	1Q	22.01	22.41	23.22
		2Q	21.01	21.37	20.93
		3Q	21.81	22.25	21.90
		4Q	21.92	22.36	22.42
		Ave	21.69	22.09	22.11

			Canadian Par	WTI NYMEX	Brent
C.	At Montreal				
	1990	4Q	32.48		34.41
		Ave	25.21		25.61
	1991	1Q	22.29		22.88
		2Q	21.30		20.59
		3Q	22.07		21.47
		4Q	22.19		22.07
		Ave	21.96		21.74

Appendix VII
Average Regular Unleaded Gasoline Prices
(Self-Serve)
1990-1991

	1990----------	----------1991----------			
	Dec. 25	March 26	June 25	Sept. 24	Dec. 31
	----------cents per litre----------				
St. John's (NFLD)	72.6	62.0	61.8	61.8	61.8
Charlottetown	68.4	65.6	60.3	60.6	61.1
Halifax*	70.6	61.7	60.3	60.2	59.9
Saint John (N.B.)*	67.3	57.7	57.7	60.0	60.0
Montreal	71.0	63.0	63.2	66.5	63.8
Toronto	58.8	54.8	57.5	57.9	47.7
Winnipeg	64.9	49.0	47.2	53.8	49.8
Regina	62.9	49.9	38.9	42.9	50.9
Calgary	60.0	42.0	47.6	50.5	49.2
Vancouver	66.6	55.4	53.2	49.9	49.6
Average	**64.6**	**55.6**	**56.1**	**57.7**	**53.7**
Consumption taxes inlcude:					
Federal	12.3	12.0	12.1	12.2	11.9
Provincial	11.4	11.6	12.9	13.1	13.1

* *Full-Serve*

Appendix VIII
Consumption Taxes on Petroleum Products
(December 1991)

	Ad valorem Mogas	Ad valorem Diesel	Gasoline Reg L	Gasoline Mid UL	Gasoline Prem UL	Diesel
	%	%	(cents per litre)	(cents per litre)	(cents per litre)	(cents per litre)
Federal Taxes						
Estimated GST (7%)			3.6*	3.9	4.1*	3.5
Excise			8.50	8.5	8.5	4.0
Provincial Taxes						
Newfoundland [(a)]	23	27	13.7	13.7	13.7	15.6
Prince Edward Island	23	26	11.7*	11.7*	11.7*	11.7*
Nova Scotia	24.5	31.5	12.3	12.3	12.3*	14.2*
New Brunswick			12.7	12.7	12.7*	13.7
Quebec [(b)]			14.0	14.0	14.0	12.6
Ontario			13.0	13.0	13.0	12.6
Manitoba			10.5	10.5	10.5	10.9
Saskatchewan			10.0	10.0	10.0	10.0
Alberta			9.0	9.0	9.0	9.0
British Columbia [(c)]	22.5	(d)	8.82	8.82	8.82	9.26
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	(e)	9.2*	9.2*	9.2*	7.8*

(a) The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay, Labrador.

(b) Reduced by varying amounts in certain remote areas and within 20 kilometres of the provincial and U.S. borders.

(c) Additional transit tax of 3.0 cents per litre in Vancouver.

(d) The tax on diesel 0.44 cents per litre higher than the unleaded tax.

(e) 85% of gasoline tax.

** changed since last quarter*

Glossary

Bitumen
A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.

Conventional area
Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.

Crude oil and equivalent
Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.

Feedstock
Raw material supplied to a refinery or petrochemical plant.

Heavy crude oil
Loosely applied, crude oils with a low API gravity (high density).

In situ recovery
With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.

Light crude oil
Crude Oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydro carbons not included under heavy crude oil.

Natural gas liquids
Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.

Oil sands
Deposits of sands and other rock aggregate that contain bitumen.

Pentanes plus
Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.

Productive capacity
The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.

Synthetic crude oil
Crude oil production treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

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The Canadian Oil Market

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Canadian Oil Markets and Emergency Planning Division
Energy Sector
Energy, Mines and Resources Canada

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Table of Contents

The Canadian Oil Market

Overview

This issue of the Canadian Oil Market reviews Canadian oil supply and demand developments during the first quarter of 1992.

Highlights

- Canada produced more crude oil during the first quarter of 1992 than a year earlier. This increase was the result of near record synthetic crude oil output and a rebound in heavy crude oil production.

- The decline in refined petroleum product sales showed signs of abating during the first quarter. Demand was higher than in the previous year but remained well below the level recorded during the first quarter of 1990.

- Reflecting the downward trend in oil consumption, crude oil imports into eastern Canada remained steady in the first quarter. A small rise in imports into Quebec, reflecting the temporary closure of the Sarnia-Montreal pipeline extension, offset a drop in foreign crude deliveries into the Atlantic region. In Ontario imports were minimal .

- Crude oil exports remained high, reflecting the decline in oil demand in Canada, the closure of the Sarnia-Montreal pipeline extension, and the upturn in Canadian oil production.

- Stocks of crude oil and petroleum products at the end of March were somewhat below a year earlier in part reflecting lower refined product sales.

- The price of regular unleaded motor gasoline fell from the previous quarter.

This issue also contains a review of the first quarter financial performance of the Canadian oil and gas industry prepared by the *Petroleum Monitoring and Information Services Division.*

The Canadian Oil Market

1. Refined Petroleum Product Consumption

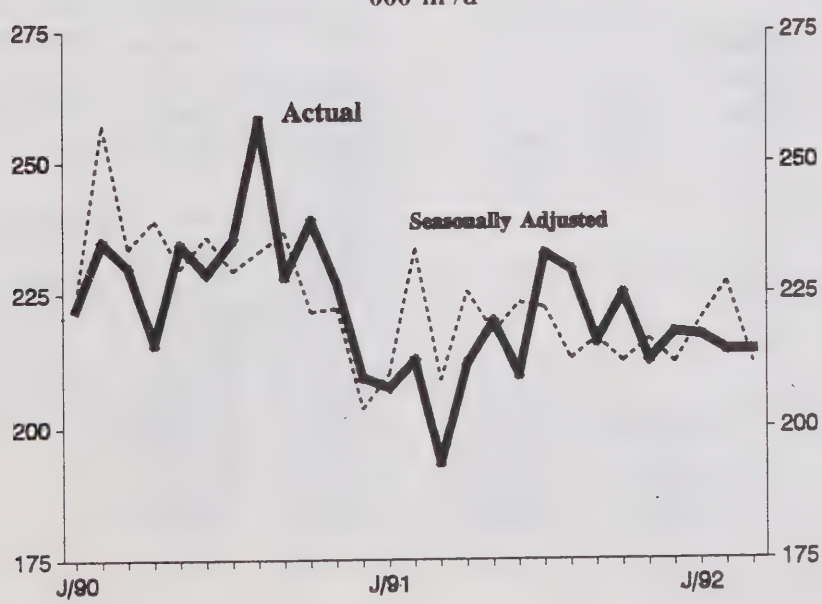
. Demand for refined petroleum products, like the economy generally, showed only feeble signs of recovery.

Actual sales of refined petroleum products averaged 215 000 m^3/d during the first quarter of 1992. This represented an increase of almost 11 000 m^3/d or 5% from the same quarter in 1991, and reflected a slight improvement in the economy, colder weather in eastern Canada, and increased use of heavy fuel oil to generate electricity. Despite the recent upturn in overall product demand, consumption remained some 14 000 m^3/d below the level recorded in first quarter 1990 when sales reached their peak before plummeting later in the year because of the combination of higher oil prices during the Persian Gulf conflict and the economic downturn.

All regions saw higher sales in the first quarter, ranging from a 17% year-over-year increase in the Atlantic to less than 1% in British Columbia. The main reason for the relatively large Atlantic increase was a surge in heavy fuel oil demand to generate electricity. The weak growth in British Columbian demand resulted, in large part, from the opening of the Vancouver Island natural gas pipeline last fall along with complementary provincial incentives designed to encourage the use of natural gas in lieu of light and heavy fuel oil. As a result, fuel oil sales in British Columbia were down by about 20% from last year, albeit on relatively small volumes.

At the national level, demand for motor gasoline rose by 4% to 84 000 m^3/d while sales of diesel fuel oil fell by 4% to 37 000 m^3/d. Heating oil sales recorded a 12% increase to 32 000 m^3/d, largely because of colder temperatures in eastern Canada. Heavy fuel oil accounted for half of the increase in total product demand. Averaging 27 000 m^3/d, heavy fuel oil sales jumped 25%, with most of the increase occurring in the Atlantic region where demand was up by almost 45%. Demand for 'other' products, which includes petrochemical feedstocks, jet fuels, asphalt and lubes, remained virtually unchanged at 36 000 m^3/d.

Figure 1.1
Refined Petroleum Product Sales
000 m^3/d



2. Drilling and Exploration Activity

. The pace of drilling activity in western Canada continues to slide with drilling in 1992 expected to fall to its lowest level in decades.

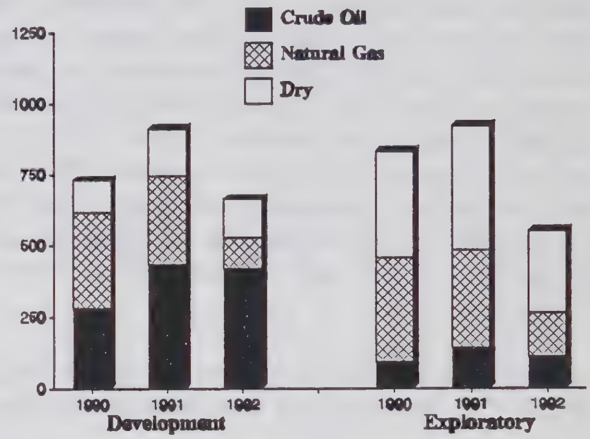
Weak natural gas and crude oil prices combined with ongoing industry cost-cutting measures pushed drilling activity in western Canada down to new lows. Despite the introduction of Alberta's crude oil royalty 'holiday' program, first quarter drilling fell short of industry expectations with only 32% of 439 available rigs reported active compared to 35% of 487 a year earlier.

In November of 1991, the government of Alberta, in an attempt to stimulate oil drilling activity, temporarily suspended the collection of royalties on all types of new and reactivated oil wells. While the announcement was for the most part well received by the industry the program proved, as predicted by some analysts, to be too little, too late. Activity in the province continued to drop in the first quarter with only 33% of 335 rigs active compared to 57% of 359 a year earlier.

Figure 2.1
Drilling Activity in Western Canada

There were 34% less crude oil and natural gas wells completed in western Canada during the first quarter compared with a year earlier. By the end of March about 1214 wells, of which 35% were dry, had been completed with total metres drilled down 25% to 1.6 million metres. However, the average depth per well increased by about 10% largely due to the emergence of horizontal drilling practices, particularly in Saskatchewan.

Figure 2.2
Well Completions
(End-of-March)



The already depressed drilling industry in western Canada is expected to continue its downward slide in 1992 with activity expected to fall below that recorded in 1991. The past two quarters of lower-than-expected drilling activity prompted the Canadian Association of Oil Drilling Contractors (CAODC) to revise downward its 1992 drilling forecast.

The CAODC now forecasts that only 23% of 425 rigs will be operating in 1992 with about 4100 crude oil and natural gas wells completed. This compares with 31% of 469 rigs in 1991 with 5388 wells completed. This expected level of activity would represent the fourth consecutive money-losing year for an industry which is said to require a 55% rig utilization rate just to break even.

3. Crude Oil Supply

. Domestic heavy crude oil producers, particularly hard hit by the post Gulf war drop in prices, are buoyed by the prospects of access to additional markets.

. Crude oil imports failed to grow in the first quarter despite the closure of the Sarnia-Montreal pipeline extension . The lack of growth reflected the general slump in crude oil demand in Canada.

3.1 Total Supply

Total crude oil supply during the first quarter of 1992 averaged about 369 000 m^3/d compared with 366 000 m^3/d a year earlier. Of this volume, domestic supply (including recycled diluent, production from Ontario, surplus NewGrade supply reinjected into the Interprovincial pipeline system and inventory changes) averaged 280 000 m^3/d. Gross imports averaged 89 000 m^3/d.

3.2 Domestic Production

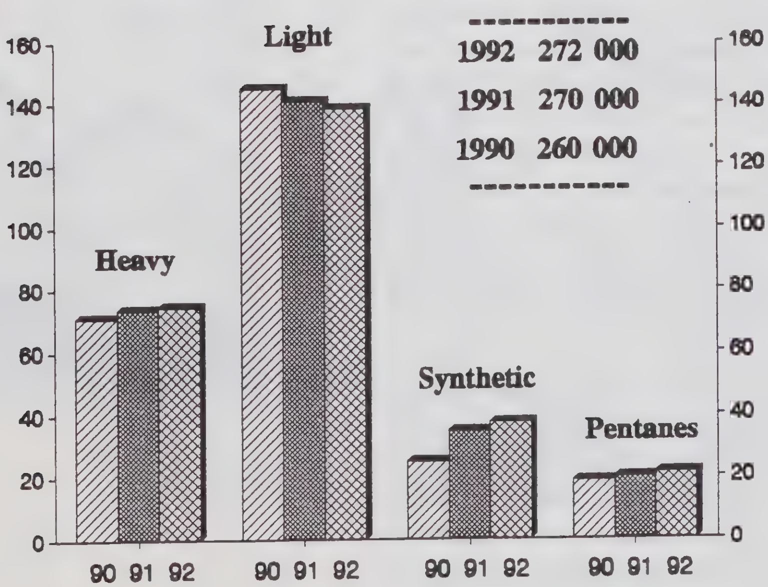
Total domestic crude oil and equivalent production during the first quarter of 1992 averaged 272 000 m^3/d. This output was about 2 000 m^3/d higher than a year earlier. Total light crude oil supply at 198 000 m^3/d proved to be somewhat higher than a year earlier due to record levels of synthetic crude oil output.

Over the first quarter, conventional light crude oil production averaged 139 000 m^3/d. Although just above the previous quarter, production was about 2 000 m^3/d below a year earlier. This decrease was more than offset be a near 3 000 m^3/d increase in synthetic crude oil output to 38 000 m^3/d. Pentanes plus production, up marginally, averaged 21 000 m^3/d.

Most of the decline in conventional light crude oil production occurred in Alberta where new production coming on stream has failed to replace falling output in older, established fields. The rate of decline has moderated somewhat in recent months due to renewed emphasis on development drilling in and around established light crude oil reservoirs.

Figure 3.2
Domestic Crude Oil Production
(First Quarter)

000 m^3/d



Conventional heavy (unblended) crude oil production recovered from the post Gulf war slump. Production during the first quarter increased by 4 000 m^3/d to about 56 000 m/d. Bitumen output, remaining well below a year earlier, averaged 19 000 m3/d.

Bitumen output is expected to recover with the start up of the Husky Bi-provincial upgrader in the Lloydminster area and the Conoco refinery in Billings, Montana. The Conoco plant is expected to process about 6 000 m^3/d of Canadian heavy crude by early summer.

The Bi-provincial upgrader is expected to convert about 7 000 m^3/d of heavy and bitumen crude into high quality synthetic crude oil. Preliminary test production is expected to occur mid-July and the plant is slated to begin commercial production in early November.

The National Energy Board (NEB) expects total domestic production to average 266 000 m^3/d in 1992, compared to 262 000 m^3/d in 1991. A further decline in conventional light production is expected to be offset by gains in synthetic crude output and pentanes production. Heavy crude and bitumen production is also expected to increase with the return of some previously shut-in production.

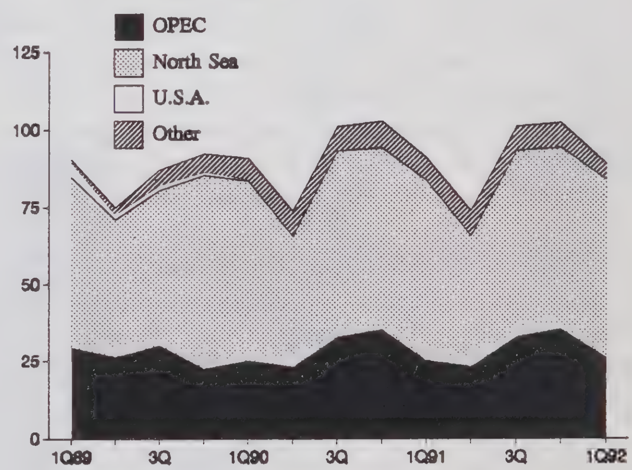
3.3 Crude Oil Imports

Reflecting the recessionary slump in oil demand in Canada, imports of crude (and partially processed) oil by refineries in eastern Canada remained virtually unchanged in the first quarter of 1992 vis-a-vis the same period a year ago. Receipts of foreign crudes averaged 89 000 m^3/d, corresponding to 38% of the total volume of crude delivered to refineries in Canada during the quarter. It should be noted that partially processed oil now comprises about 10% of imports, up from less than 2% as recently as 1990.

Reduced imports into the Atlantic region and Ontario were completely offset by a 10% increase in Quebec. Quebec imports averaged 43 000 m^3/d. The increase in Quebec reflected the mid-1991 closure of the Sarnia-Montreal extension, which made Montreal refiners virtually dependent on foreign feedstocks. However, the closure has produced just the opposite effect in Ontario where imports have dropped well below 500 m^3/d during the last year. Up until 1991, Ontario imports typically averaged between 2 000 and 3 000 m^3/d. By the first quarter of 1992, Ontario imports (entirely from the U.S) had fallen to the 200 m^3/d range. In the Atlantic region, which like Quebec, is dependent on foreign crude, imports fell by more than 4 000 m^3/d to below 46 000 m^3/d. This was in spite of a significant strengthening of demand for refined products in the region. Rather, the Atlantic decline reflected a sizeable crude oil stockdraw over the quarter; and a regional decline in refined product exports and an increase in product imports.

Most imports continued to be supplied from the North Sea. These crudes accounted for about 65% of the total. In Quebec alone, they comprised almost 90% of all deliveries, reflecting the region's traditional preference for North Sea crudes. OPEC supplied 30% of total imports, virtually all of it destined for the Atlantic refineries. Saudi Arabia and Nigeria continue to be the major OPEC suppliers.

Figure 3.3
Imports of Crude Oil by Source
000 ^{3}/d



4. Crude Oil Disposition

. The domestic refining industry remains in a slump despite a small year-over-year increase in crude oil demand.

. Canada's net crude oil export position continues to increase as a result weak domestic demand for indigenous crudes.

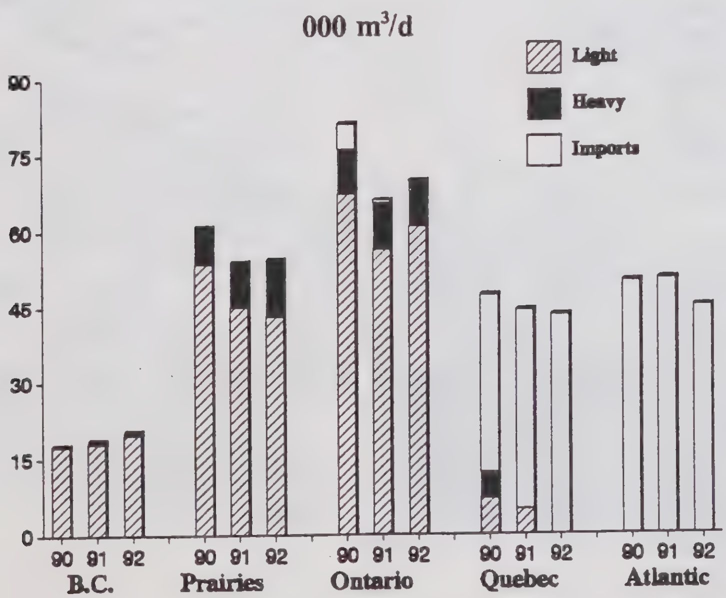
4.1 Canadian Refinery Crude Oil Receipts

Purchases of crude oil by Canadian refiners remained at depressed levels during the first quarter of 1992. Averaging 233 000 m^3/d, crude oil deliveries were only 2 000 m^3/d or 1% higher than the same period last year. The increase reflected higher receipts in Ontario and western Canada. In British Columbia, a downward trend in crude oil deliveries was reversed after one refinery reactivated its catalytic cracker and another undertook a small expansion in capacity.

Despite the modest upturn, the Canadian refining sector remains in a slump as suggested by the fact that refinery receipts remained 25 000 m^3/d below the level recorded two years earlier. Moreover, although there was an accompanying 5 000 m^3/d increase in crude runs, this appears to have had more to do with building product inventories prior to a spate of refinery turnarounds in the second quarter than to any industry perception of improved sales prospects in refined product markets.

Domestic crude oil accounted for all the incremental receipts, the level of imports virtually unchanged from last year. Deliveries of domestic crude oil averaged 144 000 m^3/d, accounting for 62% of total receipts. Except for minimal deliveries of U.S. crude to Ontario, refineries west of Quebec met all their crude oil feedstock requirements from western Canadian production. On the other hand, the temporary closure of the Sarnia-Montreal pipeline meant that the refineries in Quebec, in addition to those in the Atlantic region,

Figure 4.1
Refinery Crude Oil Receipts
(First Quarter)



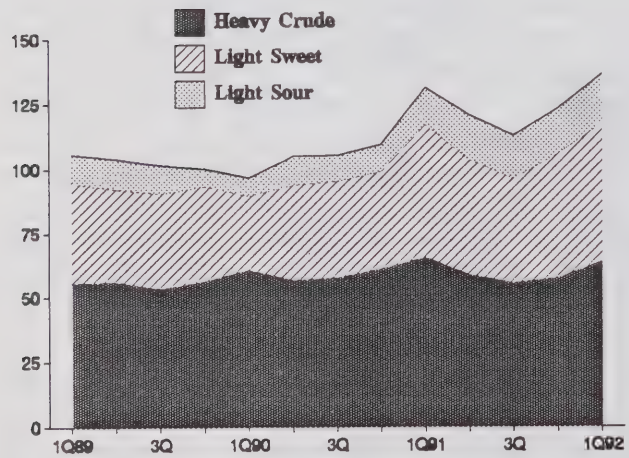
were now processing offshore imported crudes exclusively. Imports averaged 89 000 m^3/d during the quarter and were almost evenly split between the Atlantic and Quebec refiners.

There were small increases in deliveries of both Canadian light and heavy crudes. Receipts of domestic light and equivalent averaged 124 000 m^3/d. This corresponded to about two-thirds of indigenous light crude supply. The other third was exported. On the other hand, about three-quarters of domestic heavy crude production was sold in the export market, Canadian refiners limiting their demand for the heavier indigenous crudes to about 20 000 m^3/d. However, domestic demand for these heavier crudes should increase by about 7 000 m^3/d once the Bi-Provincial upgrader comes on stream towards the end of 1992.

4.2 Crude Oil Exports

First quarter crude oil exports at 136 000 m^3/d were up about 2 000 m^3/d from record highs reached a year earlier. Exports to the United States averaged 132 000 m^3/d. A 4% increase in exports to U.S. markets helped to offset weak recession-driven demand for indigenous crudes by domestic refiners.

Figure 4.2
Crude Oil Exports
000 m^3/d

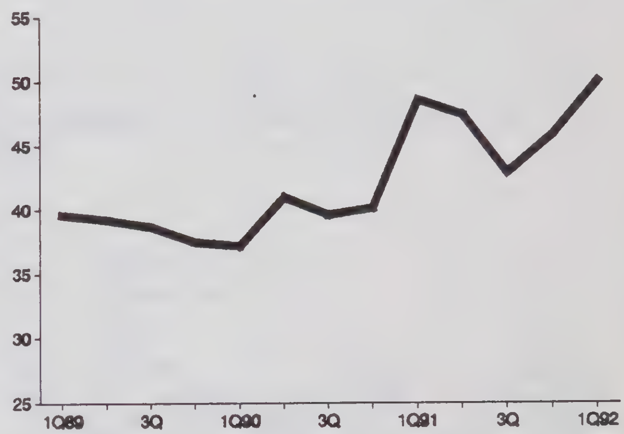


The remainder amounting to relatively small volumes of primarily light crude were tankered offshore to some Pacific Rim destinations via Trans Mountain Pipe Line's Westridge Marine terminal and delivered by pipeline to refiners on the Olympic Peninsula of Washington State.

The first quarter year-over-year increase in exports was the result of a 7 000 m^3/d jump in light crude deliveries to about 72 000 m^3/d. Heavy crude exports averaging 64 000 m^3/d were down almost 2 000 m^3/d from the year before.

As illustrated in the following graph, exports during first quarter represented about 50% of domestic crude oil production (73% of blended heavy supply and 39% of net light crude oil).

Figure 4.2.2
Crude Oil Exports
Percentage of Production



As a result of the decline in domestic demand, exports of crude oil exceeded imports by about 58 000 m^3/d. This compares with 46 000 m^3/d a year earlier. If refined petroleum products are included, Canada's total net export position increased by 7% or nearly 5 000 m^3/d to 75 000 m^3/d.

5. Pipeline Deliveries

. Trans Mountain Pipe Line deliveries of light crude oil increased as a result of reduced demand in eastern Canada.

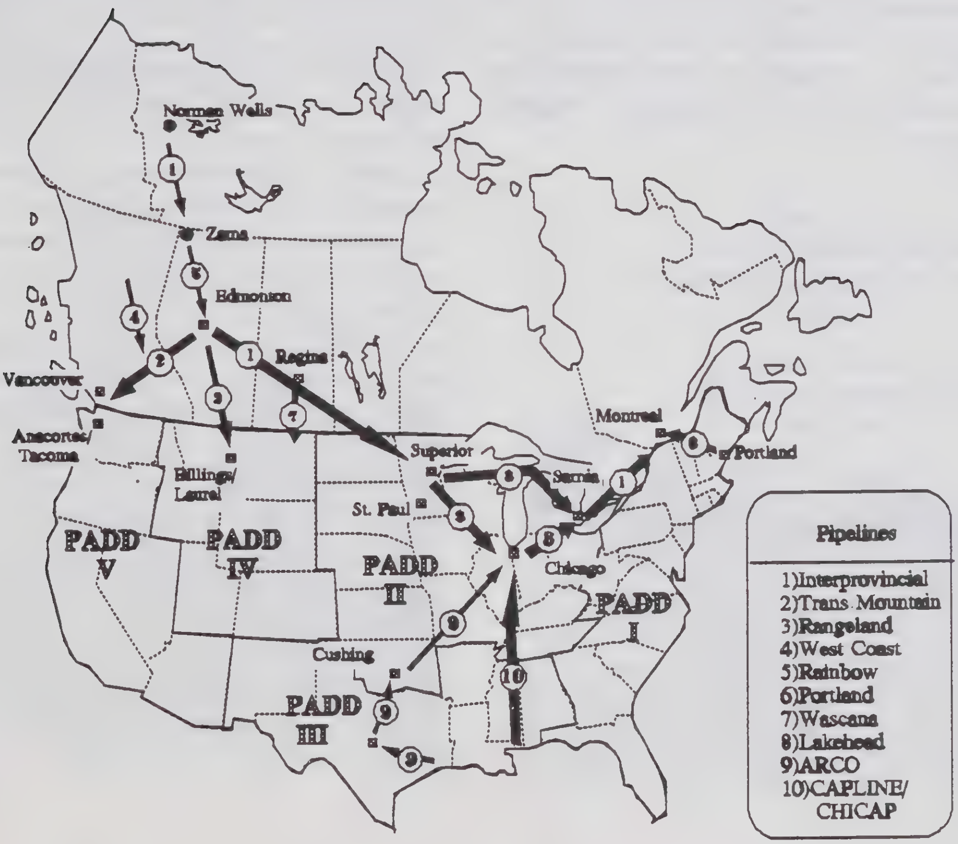
. Interprovincial Pipe Line has received approval to temporarily reopen its Sarnia-Montreal extension at the request of the Alberta Petroleum Marketing Commission.

Most Canadian crude oil is gathered at Edmonton Alberta. It is then delivered to the domestic and export market, for the most part, by a network of pipelines.

The bulk of Canadian crude exports are delivered to the United States via the Interprovincial and Lakehead pipeline system. Smaller volumes are delivered by the Trans Mountain Pipe Line to the west coast for delivery to large U.S. refineries in the Puget Sound area and tankering offshore. The Rangeland carries crude oil south into Montana.

Canadian crude oil delivered to the U.S. midwest competes in the key Chicago refining area with U.S. domestic crudes and other foreign crudes delivered through the CAPLINE/CHICAP pipeline system from the Louisiana Gulf Coast and alternatively the Arco pipeline system from Texas, Gulf Coast via Cushing, Oklahoma.

Figure 5
Major Crude Oil Pipelines



5.1 Trans Mountain Pipe Line Deliveries

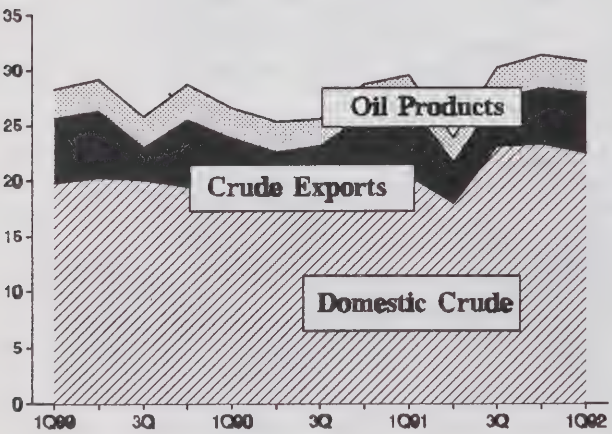
The Trans Mountain Pipe Line (TMPL) originates in Edmonton and delivers crude oil, semi-refined and refined petroleum products some 1328 kilometres west to the Vancouver area. The pipeline also receives crude from northern British Columbia at Kamloops delivered via the West Coast Pipe Line.

Deliveries during the first quarter of 1992 averaged 31 000 m^3/d, up 1 000 m^3/d from a year earlier. About 22 000 m^3/d was delivered to the Vancouver/Burnaby area. A jump in light crude deliveries offset a decrease in semi-refined product. Heavy crude oil deliveries were also down on relatively small volumes.

Deliveries of refined products to Kamloops, B.C. averaged 3 000 m^3/d an increase of about 300 m^3/d from a year earlier.

Crude oil deliveries for export averaged 6 000 m^3/d, down about 1 000 m^3/d from a year earlier. About 70% of this volume, primarily light crude oil, was delivered to TMPL's Westridge Marine Terminal for tankering offshore. Deliveries to Washington state refineries, accounting for the remainder, remained relatively unchanged.

Figure 5.1
Trans Mountain Deliveries
000 m^3/d



Reduced demand for light crude oil in eastern Canada resulted in a significant increase in deliveries to the Vancouver area and offshore. Deliveries of heavy crude were reduced due to the shut-in of some heavy crude oil production in western Canada combined with additional upgrading capabilities in the U.S. mid-west.

5.2 Interprovincial Pipe Line Deliveries

The Interprovincial Pipe Line (IPL) system consists of three major sections stretching some 3 700 kilometres from western Canada east to Montreal, Quebec.

The western section of the IPL originates at Edmonton and travels east through Regina, Saskatchewan and crosses into the United States near Gretna, Manitoba. The Lakehead Pipe Line (which on behalf of IPL owns 20% of the assets) manages the pipeline which serves the U.S. Great Lakes region via routes to the north and south of Lake Michigan to Sarnia. The eastern section of the IPL from Sarnia, Ontario to Montreal was closed in July of 1991 due to falling throughput.

Deliveries on the Sarnia-Montreal pipeline began to decline late in 1990 from nearly 20 000 m^3/d early in the year to about 5 000 m^3/d by year end. Citing increasing competitiveness of offshore crudes, shippers advised IPL that they intended to terminate domestic crude deliveries during the first quarter of 1991. As a result, IPL began to plan for the idling and deactivation of the line which at its peak in 1979/1980 delivered nearly 50 000 m^3/d to Montreal refineries. By August, IPL had drained all the remaining crude from the line, and filled it with nitrogen.

Despite the closure of the Sarnia-Montreal pipeline, total deliveries during the first quarter of 1991 increased to 240 000 m^3/d. This compares with 234 000 m^3/d the year before. U.S. markets received the lion's share of deliveries at 121 000 m^3/d with shipments to Ontario down 9% to 84 000 m^3/d. With the closure of the Sarnia-Montreal extension refiners in Quebec have become almost entirely dependent upon foreign crude.

A number of options have been considered by IPL for the idled line. Some consideration has been given to the periodic shipment of small volumes of heavy crude to Montreal as well as using a portion of the line to transport low pressure natural gas. IPL's preferred option is to reverse a part of the line which would allow for the delivery of imported crude from Montreal to a point just west of Toronto where the crude would be diverted to available lines for delivery into the Toronto and Sarnia areas.

The National Energy Board (NEB), which regulates pipelines in Canada, completed public hearings early in the year on the toll methodology that would be applied to the reversed line. The NEB announced that effective January 1, 1992 stand alone tolls would apply for a reversed Sarnia-Montreal extension. The Board also ruled on a number of other key issues relating to the line.

A few weeks prior to the NEB ruling, the Alberta Petroleum Marketing Commission (APMC), acting on behalf of several western producers announced its intention to resume crude oil deliveries to Montreal through the Sarnia-Montreal extension.

The APMC proposed the movement of 3 000 to 5 000 m^3/d of light crude to Montreal for a period of six months to a year and possibly longer. Despite the earlier decision, the NEB was requested to approve the resumption of integrated tolls on the line which had been in effect prior to line idling. The NEB agreed with the request provided that the line was operated in a west to east mode. Filling the extension with 365 000 m^3 of crude oil was scheduled to begin early in July with deliveries to Montreal expected in November.

The reactivation of the Sarnia-Montreal extention has not changed IPL's plans for the future use of the line. IPL still plans to apply to the NEB for permission to convert the segment of the extension from Sarnia to Toronto to a low pressure natural gas pipeline; and to reverse the longer segment from Toronto to Montreal to allow Ontario refiners access to offshore crude delivered to the Montreal terminus via the the Portland to Montreal pipeline system. Assuming industry support and timely regulatory approval, IPL hopes that these projects could be completed in 1994.

Figure 5.2.1
IPL Deliveries
000 m^3/d

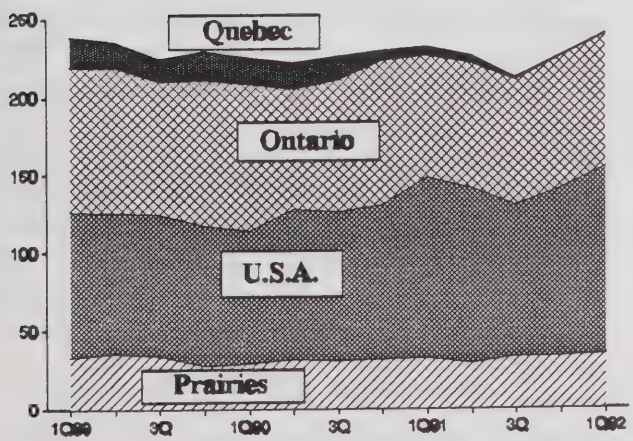
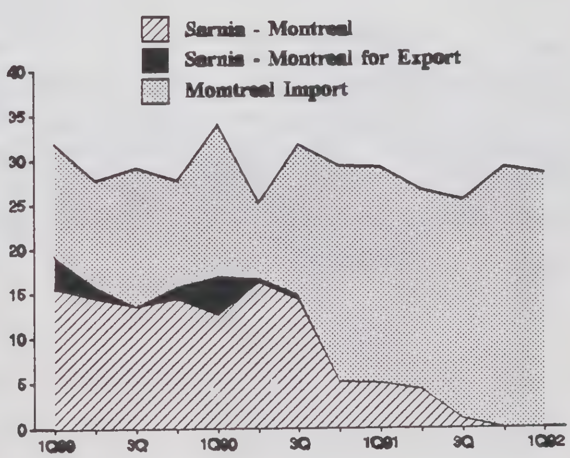


Figure 5.2.2
Deliveries to Montreal
000 m^3/d

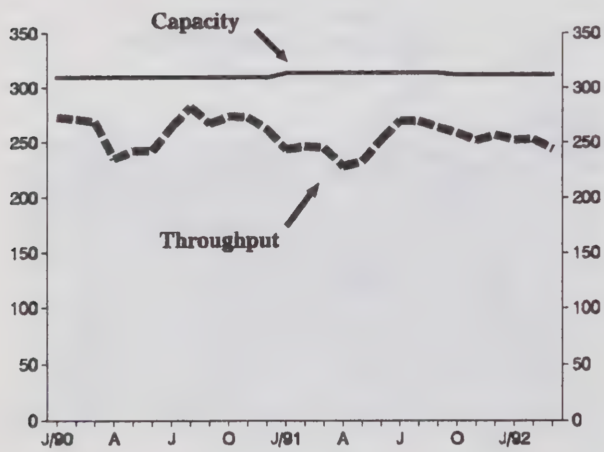


6. Refinery Activity

. The national refinery utilization rate for the second quarter of 1992 averaged 80%. This rate is expected to increase with further downsizing of the refining sector.

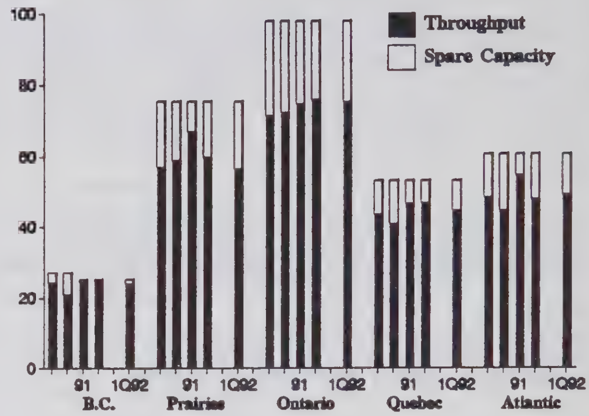
Refinery throughput will normally diverge from refinery crude oil receipts for two reasons. First, feedstocks other than crude oil are also charged in the refining process. Some of the 'other' feedstocks include gas plant butanes (used mostly by Prairie refineries) and partially processed oil (used mostly by B.C. refineries). During the first quarter of 1992, these 'other' receipts averaged 12 000 m^3/d or about 5% of total refinery feedstocks in Canada. Second, refinery throughput reflects changes in feedstock inventories. Other things being equal, an inventory drawdown will cause refinery throughput to exceed receipts - and vice versa in the case of an inventory build. Over the quarter, crude oil inventories at the national level were drawn down at a rate of more than 5 000 m^3/d.

Figure 6.1
Total Capacity and Utilization
000 m^3/d



Total throughput averaged 250 000 m^3/d during the first quarter, about 5 000 m^3/d above that recorded a year earlier. With Canadian refining capacity estimated to slightly exceed 310 000 m^3/d, this level of throughput corresponded to a national refinery utilization rate of about 80%. The utilization rate was highest in British Columbia where it almost reached nameplate capacity, and lowest in the Prairies at 74%.

Figure 6.2
Regional Capacity and Utilization
000 m^3/d



Utilization rates are likely to increase over the medium term as a result of complete or partial closure of some refineries. The anticipated downsizing of the refining sector over the next few years reflects the combination of depressed markets for refined products and the environmentally-driven need for large capital outlays to upgrade facilities in those refineries that continue to operate. In an industry where there are substantial economies of scale, the smaller refineries are particularly vulnerable to being shut down. Moreover, the upgrading costs can more easily be recovered from the higher throughput refineries. To this effect, announcements have been made that several small refineries in British Columbia are to be decommissioned with existing tankage used to store oil products pipelined in from larger sister refineries in Edmonton.

7. Crude Oil and Petroleum Product Stocks

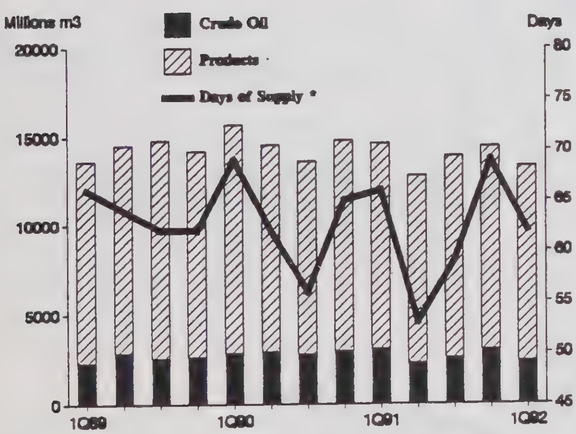
. Domestic refiners reduced their crude oil and refined product inventories in response to lower refined product demand and reflected refiners' attempts to minimize inventory costs.

Primary stocks of crude oil and refined petroleum products closed the first quarter of 1992 at 13.4 million m^3. Stocks were down 9% or 1.3 million m^3 from that recorded a year earlier. This decrease represented a 3 500 m^3/d drawdown over the year.

Of this volume, refined petroleum product stocks at 11.0 million m^3 were down 5% or 638 000 m^3 from a year earlier. Crude oil stocks were down 22% to 2.4 million m^3.

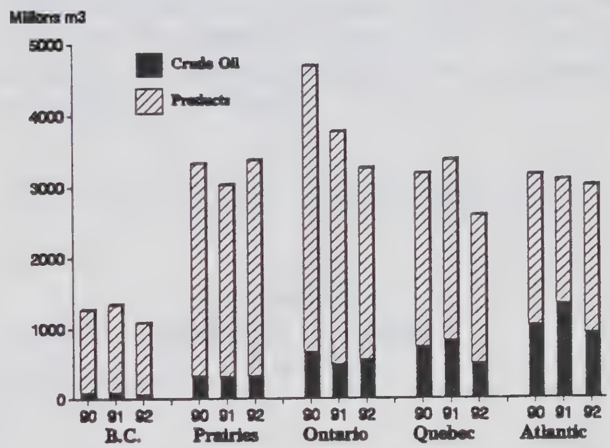
Most of the second-quarter decrease reflected the recession driven drop in demand for refined products. Stocks of crude, although lower than a year earlier, remained within normal operating levels.

Figure 7.1
Crude and Product Stocks
(End-of-quarter)



On a national basis, total stocks dropped across all regions with the exception of the Prairies. Most of this stock decline was recorded in Ontario and Quebec with both regions experiencing a significant drop in refined product stocks.

Figure 7.2
Crude and Product Stocks by Region
(End-of-quarter)



Stocks of 'main' petroleum products, at 7.3 million m^3 were down 13% or 1.1 million m^3 from the year before. An 800 000 m^3 drop in middle distillates to 2.7 million m^3 accounted for most of this decline. Stocks of motor gasoline at 3.9 million m^3 and heavy fuel oil at 714 000 m^3 were down 150 000 m^3 and 100 000 m^3, respectively.

End-of-March crude oil and refined petroleum product stocks* represented a reserve of about 62 days of supply (based on historical consumption). This compares with 68 days of supply a year earlier. Main petroleum product stocks fell to 42 days of supply from 46 days.

** Stocks do not include estimates of crude oil held in pipelines/tankage. If these stocks were to be included it is estimated that the number of days of supply would increase by about seven days.*

Figure 7.2
Total Petroleum Product Stocks
million m³

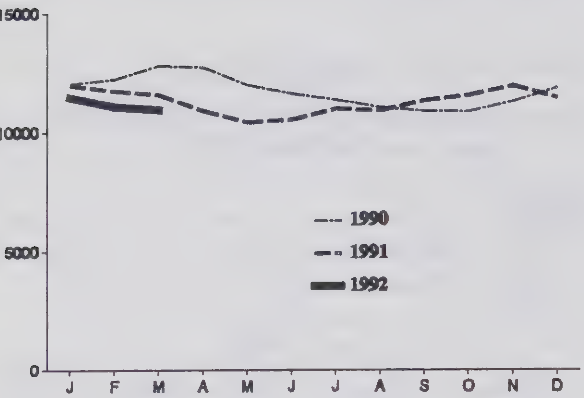


Figure 7.3
Motor Gasoline Stocks
million m³

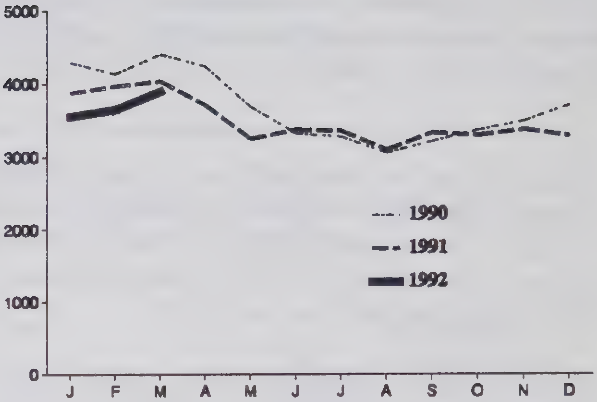


Figure 7.4
Light Fuel Oil Stocks
million m³

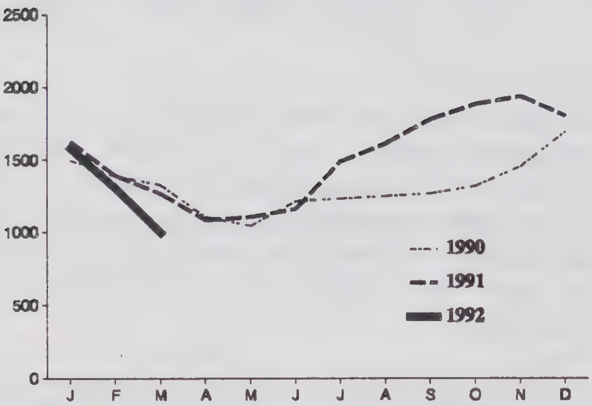


Figure 7.5
Diesel Fuel Oil Stocks
million m³

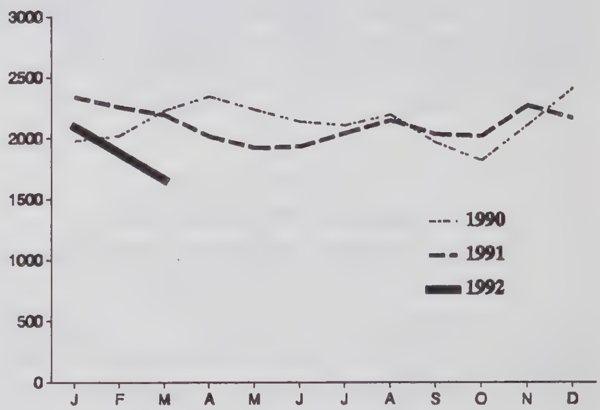


Figure 7.6
Heavy Fuel Oil Stocks
million m³

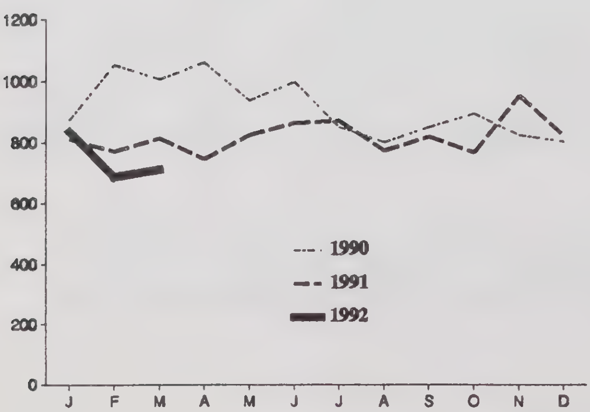
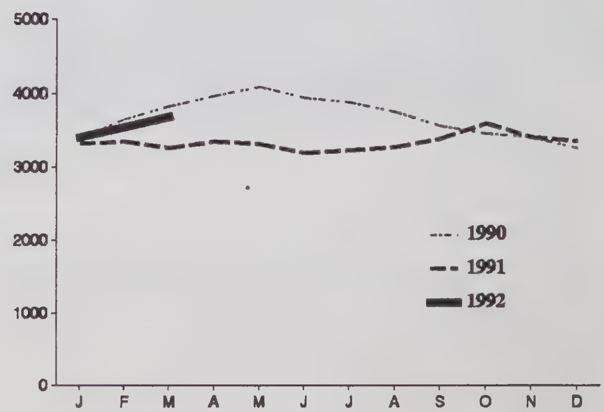


Figure 7.7
Other Petroleum Product Stocks
million m³



8. Crude Oil Prices

. International and domestic crude oil prices continued to be affected by sluggish market demand.

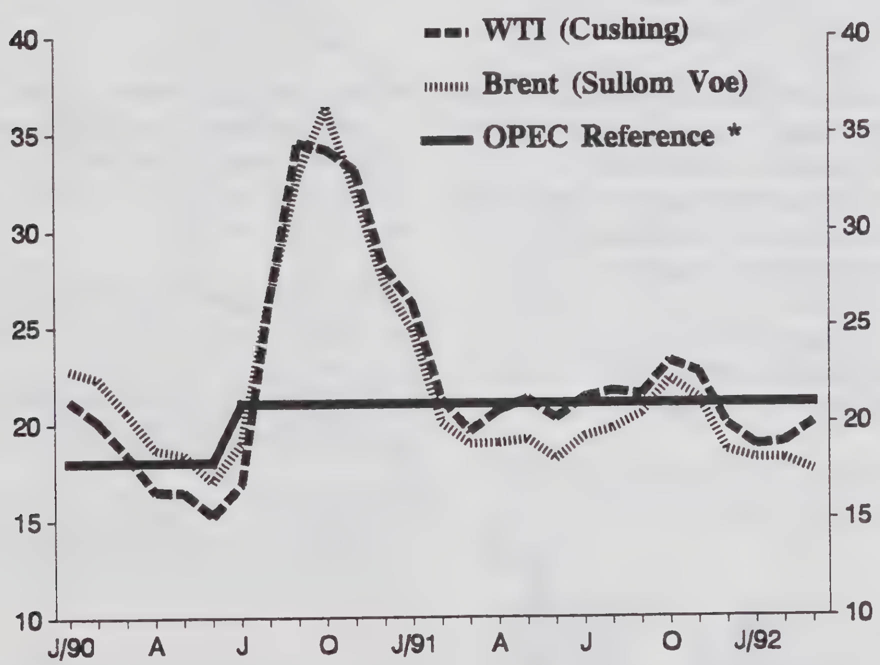
8.1 International Crude Oil Prices

Over the first quarter of 1992, sluggish demand for crude oil played a dominant role in world oil markets. Late in January, Opec members responded to relatively weak crude oil prices by voluntarily reducing crude oil production, albeit marginally. As a result, crude oil prices improved just before the February 12 OPEC Ministerial Monitoring Committee (MMC) meeting.

The outcome of the MMC meeting was disappointing as members agreed to restrain crude oil output to 23 MMB/d for the March to June period, somewhat above the level required to meet market demand. OPEC producers were once again forced to undertake damage control measures by quickly informing their customers that March liftings would indeed be reduced, thus restoring a certain measure of market confidence.

The benchmark U.S. crude, West Texas Intermediate (WTI), averaged US$18.95/bbl over the first quarter of 1992. This represented a decrease of US$3.35/bbl from the high prices recorded during the Persian Gulf crisis a year earlier.

Figure 8.1
International Crude Oil Prices
US$/bbl

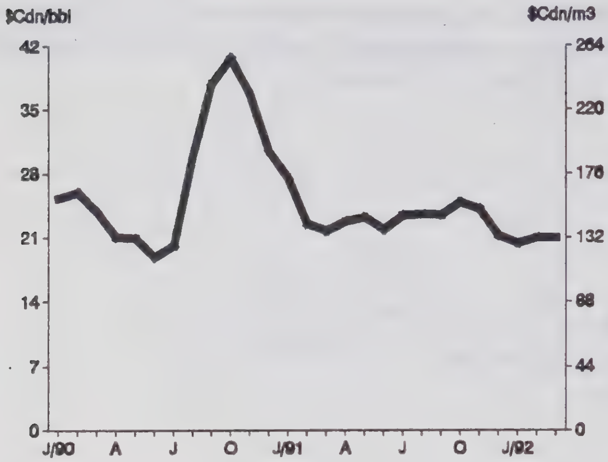


* *OPEC's reference price for a basket of seven key OPEC crudes.*

8.2 Domestic Crude Oil Prices

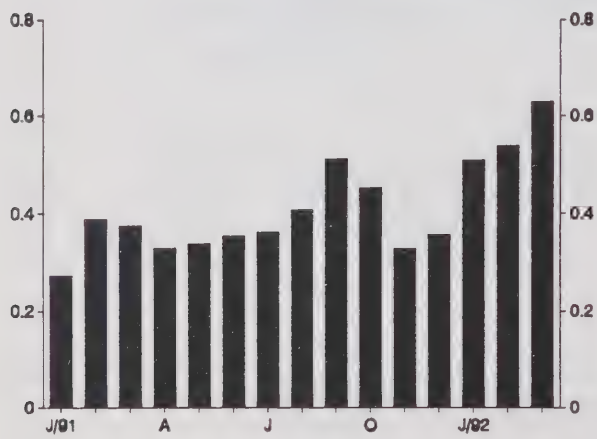
The price for Canadian Par crude oil (40° API, 0.5% sulphur), as posted by refiners, averaged \$20.80/bbl (\$130.89/m^3) in the first quarter of 1992. This price represented a decrease of \$2.61/bbl (\$6.42/m^3) from the fourth quarter of 1991.

Figure 8.2.1
Canadian Par Crude Oil Postings



The differential between WTI and Canadian Par crude at Chicago increased substantially during the first quarter of 1992, an average of US\$0.56/bbl (\$3.52/m^3), compared to the fourth quarter average of US\$0.38/bbl (\$2.41/m^3). This increase was generally attributed to weak demand in an oversupplied market.

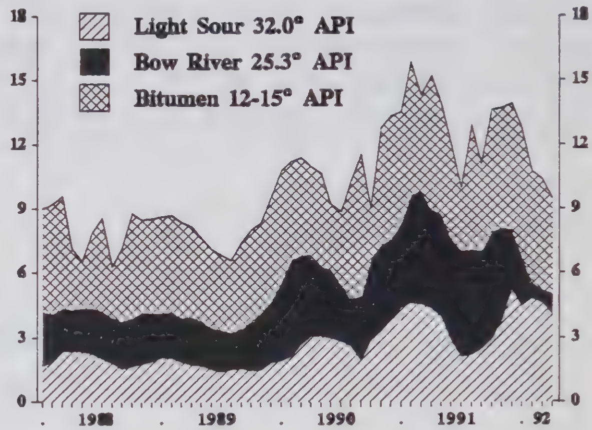
Figure 8.2.2
Canadian Par vs WTI NYMEX
CDN\$/bbl



8.3 Domestic Crude Oil Differentials

The following graph illustrates the crude oil price differentials between Canadian Par crude at Edmonton and the average posted price of Alberta Light Sour Blend, Bow River (heavy) and bitumen.

Figure 8.3
Domestic Crude Oil Price Differentials
CDN\$/bbl



For the most part, domestic crude differentials returned to more traditional levels during the first quarter of 1992 after sharp increases in 1991. The exception was for the light sour crude differential which continued to reflect flat demand.

In the first quarter of 1992, the Bow River to par crude price differential averaged \$5.85/bbl (\$36.85/m^3), down \$3.42/bbl (\$21.54 m^3) from a year earlier. Over the same period, the bitumen to par crude differential fell by \$3.23/bbl (\$20.34 m^3) to \$11.31/bbl (\$71.25 m^3).

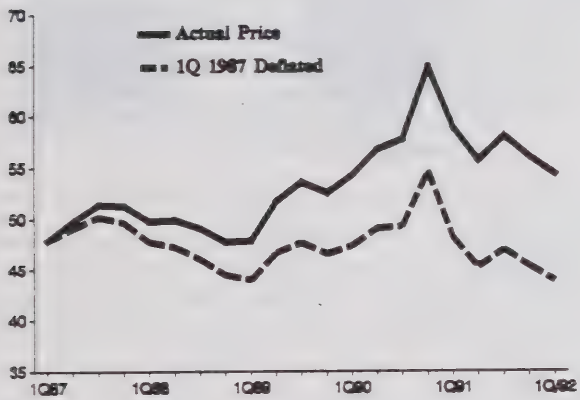
These reductions in price differentials were primarily the result of increased demand for heavy crudes in the United States and a decrease in domestic supply.

9. Petroleum Product Prices

. The price spread between Canada and the United States narrowed as Canadian gasoline prices and federal taxes decline. Provincial product taxes increased.

The price of regular unleaded gasoline averaged 53.3¢/litre during the first quarter of 1992, a decrease of 2.8¢/litre from the previous quarter's 56.1¢/litre. Over a five-year period, the actual pump price has increased 6.5¢/litre. Yet, when the tax-included pump price is adjusted for inflation, it has actually declined 8.3% or 4¢/litre from the first quarter of 1987.

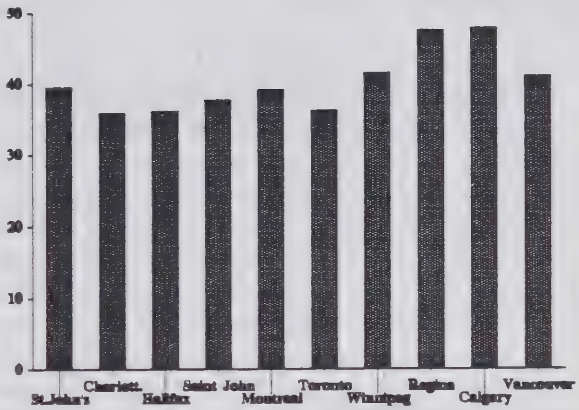
Figure 9.1
Regular Unleaded Gasoline Prices
cents per litre



Gasoline prices declined gradually throughout the first quarter of 1992. Regular unleaded gasoline fell to 52.1¢/litre in March 1992 from 54.4¢/litre at the end of the fourth quarter of 1991. Lower demand for gasoline induced price wars in several cities including Calgary, Regina, Toronto and Montreal as marketers vied for market share.

Diesel, followed the same trend as gasoline, declining 2.2¢/litre from the last quarter of 1991. Higher seasonal demand for residential furnace fuel oil allowed a higher price to be maintained - 38¢/litre during the first quarter of 1992, compared to 37.4¢/litre during the previous quarter.

Figure 9.2
Average Consumer Furnace Oil Price
cents per litre



Consumption Taxes on Petroleum Products

The aggregate federal and provincial consumption taxes on regular unleaded gasoline averaged 25.8¢/litre during the first quarter of 1992 up from 25.2¢/litre in fourth quarter 1991. The increase was entirely due to provincial tax increases (0.8¢/litre), while the federal component of the tax decreased 0.2¢/litre.

The provincial tax increase is largely attributable to the last in a series of tax changes that were announced in the 1991 provincial budgets in Ontario and Quebec that came into effect in January 1992. In Ontario, provincial taxes for regular unleaded gasoline and diesel were raised by 1.7¢/litre, while Quebec's tax increased by 0.5¢/litre for both fuels.

The drop in federal taxes is attributable to the Goods and Services Tax, which decreases as product prices decrease.

Canada vs. United States

The average price spread between the two countries was 18.9¢/litre during the first quarter of 1992, down from 20.7¢/litre in fourth quarter 1991. The narrowing price spread reflects a reduction in the ex-tax difference since refining and marketing costs increased in the U.S. and decreased in Canada during the period.

The difference in taxes between the two countries accounts for a substantial portion of the pump price differential. Taxes accounted for 81% of the pump price differential for regular unleaded gasoline during the first quarter of 1992, considerably higher than the previous quarter's 73%.

Figure 9.3
Average Retail Price of Motor Gasoline
(Canada vs United States)

cents per litre

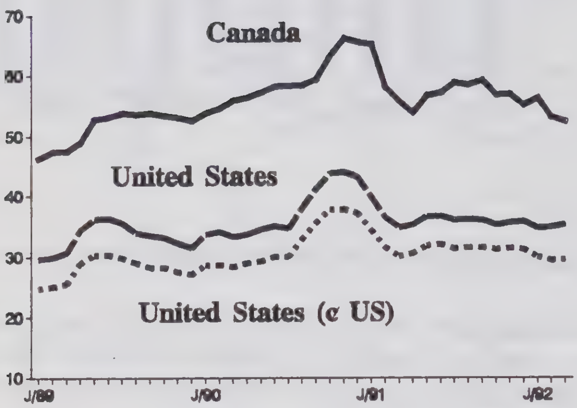
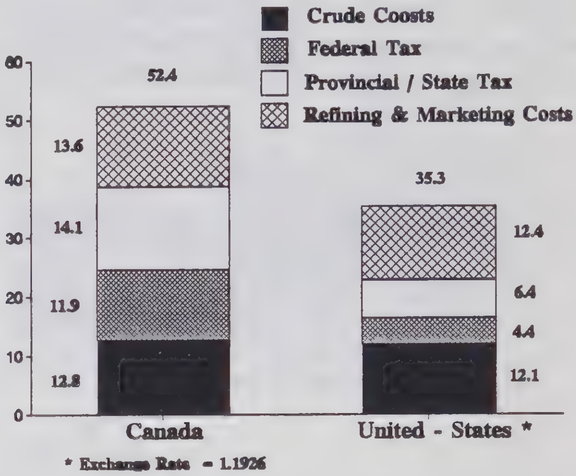


Figure 9.4
Breakdown of Average Pump Price
(March 1992)

cents (CDN) per litre



10. Financial Performance of the Canadian Oil and Gas Industry

The following section was prepared by the Petroleum Monitoring and Information Services Division of the Economic and Financial Analysis Branch. Further information is available from V. Stanciulescu (613) 995-2100 and F. Laberge (613) 996-8035.

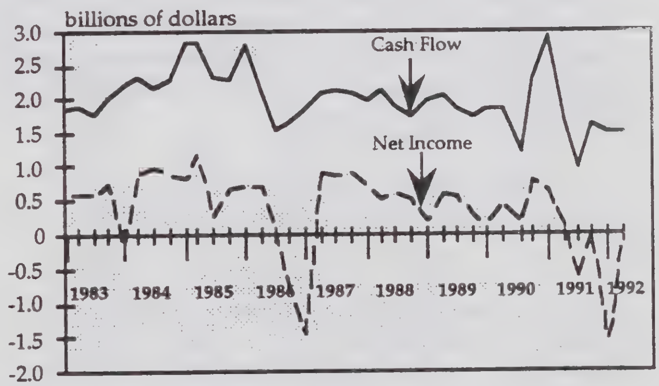
- Internal cash flow decreased 7% to $1.5 billion in the first quarter of 1992 from $1.6 billion in the corresponding 1991 period.
- Net income after unusual items declined to $70 million in the first quarter of 1992 from $95 million in the same 1991 period.
- Gross capital expenditures decreased 18% to $1.6 billion in the first quarter of 1992.
- The reinvestment rate declined to 104% from 120% in the first quarter of 1991.
- Dividend payments in the first quarter of 1992 decreased 29% to $250 million from $350 million.
- The petroleum industry's rate of return on capital employed for the first quarter of 1992 was 0.6% vs. 0.7% for the same period in 1991.
- Long-term debt as a percentage of capital employed increased to 48% from 45% at the end of 1991.

Total sales revenues declined 16% to $9.2 billion in the first quarter of 1992 from $11 billion in the corresponding 1991 period. Upstream revenues declined as a result of lower crude oil and marketable natural gas prices. Downstream revenues fell due to lower product prices in 1992, which resulted from reduced feedstock costs compared to those existing at the beginning of 1991. Crude oil prices rose sharply in the last five months of 1990 and the first part of January 1991. The oil products industry was left with large inventories produced with high-cost crude oil. While companies were unable to recover the full cost of their inventories in the first quarter of 1991, prices were well above those in the first quarter of 1992.

In addition to higher crude oil and marketable gas prices in the first quarter of 1991, the sale of crude oil into the futures market resulted in higher revenues. This hedging operation was a significant source of revenue for a number of oil and gas producers. For the Canadian producers, the effect of lower international prices was partially offset by a weaker Canadian dollar in the first quarter of 1992.

Internal cash flow decreased $115 million (7%), from $1.6 billion in the first quarter of 1991 to $1.5 billion in the corresponding 1992 period. The $1.8 billion (16%) drop in revenues and the fractional rise in interest expense more thar offset the impact of a $1.6 billion (18%) decline in 'Other expenses'. The latter category includes operating costs, cost of goods sold and royalty payments. The main reason for the decline in 'Other expenses' was the change in accounting for cost of goods sold, a major expense in the Oil Products business. The 1992 results reflected the adoption by a number of integrated companies of the Last-In, First-Out (LIFO) method of inventory valuation, whereas the 1991 results were largely based on the First-In, First-Out (FIFO) method. High-cost crude oil was included in cost of goods sold in the first quarter of 1991 but this did not happen in 1992. Had this accounting change been applied retroactively, the value of cost of goods sold would have been much smaller in 1991, reflecting only the actual drop in crude oil prices.

Figure 10.1 Net Income and Cash Flow Quarterly Data(1)



(1) While the 1992 results include the effects of changes in accounting methods, such as the LIFO/FIFO inventory valuation and future removal and site restoration costs, prior years' data have not been restated even if several companies applied the changes retroactively.

Net income from all Canadian operations of the industry fell to $70 million in the first quarter of 1992 from $95 million in the corresponding 1991 period. Aside from the factors affecting cash flow, the decline was due to write-offs of $50 million in 1992 vs. write-offs of $30 million in 1991, lower equity earnings and slightly higher depreciation,

depletion and amortization. Part of the increase in depletion charges was as a result of the inclusion of accrued costs for future site restoration in 1992, following a CICA recommendation.

Partly offsetting the decline in net income were recoveries of $110 million in deferred taxes in the first quarter of 1992 compared with recoveries of $70 million in the corresponding 1991 period.

Canadian-controlled companies' cash flow declined $55 million (8%) to $625 million in the first quarter of 1992 from $680 million in the corresponding 1991 period. The cash flow decline was due to lower revenues (down $450 million) and higher current income taxes (up $80 million). 'Other expenses', which includes operating and feedstock costs, and royalties, were down $475 million.

Net income rose to $25 million in the first quarter of 1992 compared to $20 million in the corresponding 1991 period.

Foreign-controlled companies' cash flow declined $60 million, or 6%, to $890 million in the first quarter of 1992 from $950 million in the same 1991 period. Sales revenues declined to $6.1 billion (down $1.3 billion). 'Other expenses', which includes operating and feedstock costs, and royalty payments, dropped $1.1 billion. Current income taxes fell $115 million to $180 million.

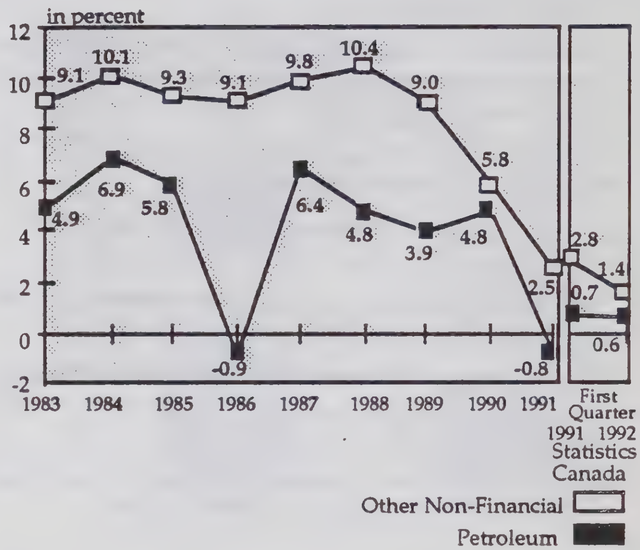
Net income declined $35 million or 45%, to $40 million in 1992 from $75 million in 1991.

Overall gross capital expenditures for the petroleum industry decreased 18% ($365 million) to $1.6 billion in the first quarter of 1992. Net of grants, incentives and contributions, capital expenditures declined 19% to $1.6 billion. The decline occurred as a result of reduced exploration and development expenditures.

Exploration and development spending declined 37% to $715 million in the first quarter of 1992, while other capital expenditures on new construction, buildings, machinery and equipment, increased 6% to $900 million. Gross capital outlays for Canadian-controlled companies declined 29% to $690 million, while those of foreign-controlled companies decreased 9% to $925 million (Table 10.1).

The petroleum industry's annualized **rate of return on capital employed** at the end of the first quarter of 1992 was 0.6% vs. 0.7% for the same 1991 period. The other non-financial industries (excluding petroleum) recorded a rate of return on capital employed of 1.4% for the first quarter 1992, vs. 2.8% in the same 1991 period (Figure 10.2 and Note).

Figure 10.2 Rates of Return on Capital Employed



Dividend payments by the petroleum industry decreased 29% to $250 million in the first quarter of 1992 from $350 million in the corresponding 1991 period. Dividends paid by Canadian-controlled companies declined 38% to $75 million, while dividend payments by foreign-controlled companies dropped 25% to $175 million.

The total reinvestment rate decreased to 104% in the first quarter of 1992 from 120% in the same period in 1991 (Table 4). The reinvestment rate for Integrateds and Refiners increased to 95% from 94%, while the rate for the Oil and Gas Producers group fell to 112% from 137%.

Note: This report was prepared from quarterly data obtained from individual companies via Statistics Canada. In contrast to the semi-annual monitoring survey, the report covers the combined results of upstream, downstream and other Canadian operations but excludes the results of Canadian companies' foreign activities. In addition, this report contains about 50 fewer companies, mostly small or government owned. Nonetheless, the information contained in this analysis gives a reliable overview of the industry's financial performance for the first quarter of 1992.

Table 10.1

Capital Expenditures of Petroleum Industry
First Quarter

	Total Industry 1991	1992	Change %	Canadian-Controlled 1991	1992	Change %	Foreign-Controlled 1991	1992	Change %
	$ millions			$ millions			$ millions		
Exploration and Development (E&D)									
E&D Expensed (1)									
Land & Lease Acquisition and Retention	23	24	7	4	5	25	19	19	2
Drilling Expenditures	118	80	-32	55	21	-62	63	59	-6
Geological and Geophysical	82	58	-29	8	6	-25	74	52	-30
Total E&D Expensed	223	162	-27	67	32	-52	156	130	-17
E&D Capitalized									
Land & Lease Acquisition and Retention	125	122	-2	64	50	-22	61	72	18
Drilling Expenditures	676	380	-44	362	212	-41	314	168	-46
Geological and Geophysical	104	50	-52	69	28	-59	36	22	-39
Total E&D Capitalized	905	552	-39	495	290	-41	411	262	-36
Total Exploration and Development	**1128**	**714**	**-37**	**562**	**322**	**-43**	**567**	**392**	**-31**
Other Capitalized Expenditures									
Mining	22	18	-18	12	11	-8	10	7	-30
New Const., Build., Mach., and Equip.	757	742	-2	368	330	-10	389	411	6
Used Build., Mach., Equip., & Land	21	100	-	7	9	29	14	91	-
Other Capital Expenditures	48	38	-21	17	16	-6	30	22	-27
Total Other Capital Expenditures	848	898	6	404	366	-9	443	531	20
Total Capital Expenditures	**1976**	**1612**	**-18**	**966**	**688**	**-29**	**1010**	**923**	**-9**
Capital Grants	16	28	75	8	13	63	8	15	88
Net Capital Expenditures	**1960**	**1584**	**-19**	**958**	**675**	**-30**	**1002**	**908**	**-9**

(1) Excludes mining expenditures.

Table 10.2
Income Statement
First Quarter

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1991	1992	Change %	1991	1992	Change %	1991	1992	Change %
	$ millions			$ millions			$ millions		
Sales Revenues	**10968**	**9250**	**-16**	**3651**	**3194**	**-13**	**7317**	**6056**	-17
Other Revenues									
Interest from Canadian Sources	82	78	-5	34	43	27	48	35	-28
Dividends from Canadian Corporations	23	32	37	10	6	-38	13	26	92
Foreign Dividends and Interest Revenues	5	2	-48	1	1	-	4	1	-76
Total Revenues	**11078**	**9362**	**-15**	**3695**	**3243**	**-12**	**7382**	**6117**	-17
Expenses									
E & D Expensed	229	166	-28	67	33	-51	162	133	-18
D, D & A Charges	1431	1448	1	558	632	13	873	815	-7
Other Expenses	8637	7068	-18	2764	2287	-17	5873	4781	-19
Interest Expenses	497	499	-	230	231	-	268	268	-
Total Operating Expenses	**10794**	**9181**	**-15**	**3618**	**3183**	**-12**	**7176**	**5998**	-16
Other Transactions									
Gains on Translation of Currency	-	-3	-	-19	-	-	19	-2	-
Gains on Sale of Assets	61	91	49	5	43	-	56	48	-14
Write-offs and Valuation Adjustments	-28	-49	-	-3	-1	-	-26	-49	-
Income before Income Taxes	**316**	**220**	**-30**	**61**	**103**	**68**	**255**	**117**	-54
Income Taxes									
Current	313	278	-11	21	101	-	292	178	-39
Deferred (tax allocation method)	-69	-112	-	53	-8	-	-123	-104	-
Net Income after income taxes	**73**	**54**	**-26**	**-13**	**10**	**-**	**85**	**43**	-49
Other Income									
Equity Income	25	16	-36	34	17	-50	-11	-1	-
Extraordinary Items	-	-	-	-	-	-	-	-	-
Net income after Extraordinary Items	**97**	**69**	**-29**	**22**	**27**	**24**	**76**	**42**	-45
Cash Flow	**1631**	**1517**	**-7**	**681**	**626**	**-8**	**949**	**891**	-6

Table 10.3
Balance Sheet

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	Dec. 31 1991	Mar. 31 1992	Change %	Dec. 31 1991	Mar. 31 1992	Change %	Dec. 31 1991	Mar. 31 1992	Change %
	$ millions			$ millions			$ millions		
Cash, Investments and Marketable Securities	**437**	**799**	**83**	**225**	**380**	**69**	**212**	**419**	97
Accounts Receivable:									
Trade (include affiliates)	5280	4616	-13	1864	1565	-16	3417	3051	-11
All Other	646	685	6	285	218	-24	361	467	29
Total	5926	5301	-11	2149	1783	-17	3778	3518	-7
Inventories	3413	3474	2	1138	1141	-	2275	2333	3
Other Current Assets	**2199**	**2218**	1	**984**	**1002**	**2**	**1214**	**1215**	-
Total Current Assets	11975	11792	-2	4496	4306	-4	7479	7485	-
Net Fixed and Depletable Assets	59703	59128	-1	24656	24380	-1	35047	34748	-1
Other Long-term Assets	7405	7673	4	4035	3986	-1	3370	3687	9
Total Assets	79083	78593	-1	33187	32672	-2	45896	45920	-
Accounts payable:									
Trade (include affiliates)	4362	4002	-8	1759	1622	-8	2603	2381	-9
All Other	2037	1968	-3	529	606	15	1509	1361	-10
Total	6399	5970	-7	2287	2228	-3	4112	3742	-9
Other Current Liabilities	**3174**	**3005**	-5	**1272**	**1319**	**4**	**1902**	**1686**	-11
Total Current Liabilities	9573	8975	-6	3559	3547	-	6014	5428	-10
Long-term Debt	23297	24335	4	9511	9373	-1	13786	14962	9
Accumulated Deferred Income Taxes	9964	9543	-4	4011	3754	-6	5954	5789	-3
Other Long-term Liabilities	**3352**	**4240**	**26**	**1199**	**1802**	**50**	**2153**	**2437**	13
Shareholders' Equity									
Common	13992	13637	-3	8016	7952	-1	5975	5686	-5
Preferred	2822	2403	-15	1461	1373	-6	1361	1030	-24
Retained earnings	11486	10853	-6	2552	1992	-22	8934	8861	-1
Contributed surplus	4597	4607	-	2878	2879	-	1719	1727	-
Total Liabilities, Deferred Taxes and Equity	79083	78593	-1	33187	32672	-2	45896	45920	-
Working Capital	2402	2817	17	937	759	-19	1465	2057	40

Appendix I
Production of Crude Oil and Equivalent
(000 m^3/d)

	1990 Year	1991 1Q	1991 2Q	1991 3Q	1991 4Q	1991 Year	1992 1Q
A. Light and Equivalent							
Conventional							
Alberta	116.8	116.0	110.1	110.2	112.5	112.2	113.6
B.C.	5.3	5.6	5.3	5.5	5.7	5.5	5.6
Saskatchewan	11.7	11.6	11.0	10.5	11.4	11.1	11.7
Manitoba	2.0	2.0	1.9	1.9	1.9	1.9	1.8
Ontario	0.6	0.6	0.7	0.6	0.6	0.6	0.6
Other	5.0	5.2	5.2	5.2	5.2	5.2	5.3
Total	**141.4**	**141.0**	**134.2**	**133.9**	**137.3**	**136.5**	**138.6**
Synthetic							
Suncor	8.2	9.9	10.0	9.4	9.1	9.6	10.2
Syncrude	24.6	25.2	22.8	27.4	29.6	26.3	27.6
Total	**32.8**	**35.1**	**32.8**	**36.8**	**38.7**	**35.9**	**37.8**
Pentanes Plus (excluding diluent)	**6.4**	**6.4**	**6.6**	**5.6**	**9.0**	**6.9**	**8.6**
Total Light	**180.6**	**182.5**	**173.6**	**176.3**	**185.0**	**179.3**	**185.0**
B. Heavy Crude							
Alberta							
Conventional	28.3	30.1	30.0	30.0	32.1	30.6	33.0
Bitumen	21.5	21.2	18.8	21.5	16.5	19.5	18.5
Diluent	9.1	10.2	8.3	9.8	8.6	9.3	9.4
Total	**58.9**	**61.5**	**57.1**	**61.3**	**57.2**	**59.4**	**60.9**
Saskatchewan							
Conventional	21.5	22.3	21.1	22.2	23.4	22.3	23.0
Diluent	2.8	3.4	2.8	2.9	3.3	3.1	3.4
Total	**24.3**	**25.7**	**23.9**	**25.1**	**26.7**	**25.4**	**26.4**
Total Heavy	**83.2**	**87.2**	**81.0**	**86.4**	**83.9**	**84.8**	**87.3**
C. Production	**263.8**	**269.7**	**254.6**	**262.7**	**268.9**	**264.1**	**272.1**

Appendix II
Supply and Disposition of Crude Oil and Equivalent
(000 m^3/d)

	1990 Year	1991 1Q	1991 2Q	1991 3Q	1991 4Q	1991 Year	1992 1Q
A. Light and Equivalent							
Supply							
Production	180.7	182.7	173.5	176.3	185.0	179.4	185.2
Newgrade	1.4	2.4	0.3	2.2	3.3	2.0	3.4
Draw/(Build)	3.8	5.3	9.8	8.9	8.1	8.1	7.9
Net Supply	185.9	190.4	183.6	187.4	196.4	189.5	196.5
Domestic Demand							
Atlantic	0	0	0	0	0	0	0
Quebec	8.1	4.9	3.2	2.6	0	2.7	0
Ontario	64.7	56.6	56.2	59.6	63.0	58.8	61.2
Prairies	50.2	45.1	46.0	47.9	47.8	46.6	43.2
B.C.	18.1	18.1	16.5	20.3	20.4	18.9	20.0
Total	**141.1**	**124.7**	**121.9**	**130.3**	**131.1**	**127.0**	**124.4**
Exports	**44.8**	**65.6**	**61.8**	**57.0**	**65.2**	**62.4**	**72.1e)**
Total Demand	**185.9**	**190.3**	**183.7**	**187.3**	**196.3**	**189.4**	**196.5**
B. Heavy Crude (Blended)							
Supply							
Production	83.2	87.2	81.1	86.4	83.9	84.7	87.4
Recycled Diluent	1.0	0.7	1.3	1.5	0.5	1.0	0.8
Draw/(Build)	(0.7)	(3.1)	(4.7)	(6.2)	(5.9)	(5.0)	(1.7)
Net Supply	83.5	84.8	77.7	81.7	78.5	80.7	83.6
Domestic Demand							
Atlantic	0.4	0	0	0	0	0	0
Quebec	3.8	0	0	0	0.1	0.1	0
Ontario	8.7	9.1	11.4	10.9	9.3	10.2	7.7
Prairies	10.8	9.1	6.7	14.4	10.7	10.3	11.4
B.C.	0.4	0.5	0.5	0.7	0.7	0.6	0.6
Total	24.1	18.8	18.7	25.9	20.8	21.1	**19.6**
Exports	**59.4**	**66.1**	**58.9**	**55.7**	**57.8**	**59.6**	**64.0e)**
Total Demand	**83.5**	**84.9**	**77.6**	**81.6**	**78.6**	**80.7**	**83.6**

Appendix III
Crude Oil Exports by Destination
(000 m^3/d)

		1990 Year	1991 1Q	2Q	3Q	4Q	1991 Year	1992 1Qe)
U.S. PAD Districts *								
I	Light	7.3	6.5	6.8	8.9	6.8	7.2	
	Heavy	1.3	1.7	1.0	1.0	1.5	1.3	
	Total	**8.6**	**8.2**	**7.8**	**9.9**	**8.3**	**8.5**	
II	Light	27.0	47.2	42.2	34.1	44.5	41.9	
	Heavy	51.9	55.5	54.3	48.3	49.2	51.8	
	Total	**78.9**	**102.7**	**96.5**	**82.4**	**93.7**	**93.7**	
III	Light	0	0	0	0	0	0	
	Heavy	1.3	3.1	0	0.6	2.5	1.5	
	Total	**1.3**	**3.1**	**0**	**0.6**	**2.5**	**1.5**	
IV	Light	10.7	9.4	10.5	12.2	12.3	11.0	**(Data not**
	Heavy	3.0	2.9	2.2	3.7	3.4	3.0	**available)**
	Total	**12.4**	**12.3**	**12.7**	**15.9**	**15.7**	**14.0**	
V	Light	0.7	1.3	1.3	1.8	0.9	1.3	
	Heavy	0.9	0.4	0.7	0.4	0.4	0.5	
	Total	**1.6**	**1.7**	**2.0**	**2.2**	**1.3**	**1.8**	
Total U.S.	**Light**	**44.4**	**64.4**	**60.8**	**57.0**	**64.5**	**61.5**	
	Heavy	**58.4**	**63.6**	**58.2**	**54.0**	**57.0**	**58.0**	
	Total	**102.8**	**128.0**	**119.0**	**111.0**	**121.5**	**119.5**	
Offshore	Light	0.1	0.8	0.8	0	0.9	0.6	
	Heavy	1.2	2.3	0.8	1.7	0.9	1.4	
	Total	**1.4**	**3.1**	**1.6**	**1.7**	**1.8**	**2.0**	
Total	**Light**	**44.5**	**65.2**	**61.6**	**57.0**	**65.4**	**62.1**	72.1
	Heavy	**59.6**	**65.9**	**59.0**	**55.7**	**57.9**	**59.4**	64.0
	Total	**104.1**	**131.1**	**120.6**	**112.7**	**123.3**	**121.5**	136.1

* *U.S. Petroleum Administration for Defense (PAD) Districts*

Appendix IV
Pipeline Deliveries
(000 m^3/d)

	1990 Year	1991 1Q	2Q	3Q	4Q	1991 Year	1992 1Q
A. Trans Mountain Pipe Line (TMPL)							
Domestic Deliveries							
Light Crude	14.6	14.5	14.1	18.7	19.7	16.8	19.3
Heavy Crude	0.3	0.4	0.2	1.1	0.3	0.5	0
Semi Refined Poducts	5.3	5.5	3.7	3.2	3.2	3.9	3.1
Refined Products	2.6	2.4	2.0	2.7	2.9	2.5	2.7
Total	**22.8**	**22.8**	**20.0**	**25.7**	**26.1**	**23.7**	**25.1**
Foreign Deliveries							
Tankers	3.0	5.7	2.2	3.5	4.5	4.0	4.0
Puget Sound Area	0.8	1.1	1.6	1.0	0.8	1.1	1.7
Total	**3.8**	**6.8**	**3.8**	**4.5**	**5.3**	**5.1**	5.7
Total TMPL	**26.6**	**29.6**	**23.8**	**30.2**	**31.4**	**28.8**	30.8
B. Interprovincial Pipe Line (IPL)							
Domestic Deliveries							
Light Crude	84.1	74.2	74.8	73.1	74.3	74.1	74.0
Heavy Crude	17.4	12.3	12.3	16.0	14.5	13.8	13.6
Other (1)	29.7	28.6	26.5	25.4	28.1	27.2	31.3
Total	**131.2**	**115.1**	**113.6**	**114.5**	**116.9**	**115.1**	**118.9**
Foreign Deliveries							
Light Crude	34.6	54.2	49.6	42.6	51.4	49.5	59.5
Heavy Crude	53.2	57.6	55.3	49.5	50.6	53.2	54.8
Other (1)(2)	7.1	6.8	7.8	5.6	7.0	6.7	6.6
Total	**94.9**	**118.6**	**112.7**	**97.7**	**109.0**	**109.4**	**120.9**
Total IPL	**226.1**	**233.7**	**226.1**	**212.2**	**225.9**	**224.5**	**239.8**
C. Pipelines to Montreal							
IPL Deliveries							
To Montreal	12.3	4.9	4.2	1.0	0	2.4	0
For Export/Transfer	1.2	0	0	0	0	0	0
Total IPL	**13.5**	**4.9**	**4.2**	**1.0**	**0**	**2.4**	**0**
Portland-Montreal							
Montreal Imports (3)	16.7	24.2	22.4	24.4	29.1	25.0	28.4
Total Montreal Receipts	**29.0**	**29.1**	**26.6**	**25.4**	**29.1**	**27.4**	**28.4**

(1) includes petroleum products and NGL's.
(2) includes US domestic crudes delivered to the U.S.
(3) includes cargos imported directly into Montreal

Appendix V
Canadian Refinery Receipts
(000 m^3/d)

	1990 Year	1991 1Q	1991 2Q	1991 3Q	1991 4Q	1991 Year	1992 1Q
A. Domestic Receipts							
Light & Equivalent							
Atlantic	0	0	0	0	0	0	0
Quebec	8.1	4.9	3.1	2.6	0	0	0
Ontario	64.7	56.6	56.2	59.6	63.0	58.9	61.2
Prairies	50.2	45.1	46.0	47.9	47.7	46.7	43.2
B.C.	18.1	18.1	16.5	20.3	20.4	18.8	19.9
Total	**141.1**	**124.7**	**121.8**	**130.4**	**131.1**	**124.4**	**124.3**
Heavy							
Atlantic	0.4	0	0	0	0	0	0
Quebec	3.9	0	0	0	0.1	0	0
Ontario	8.6	9.1	11.4	10.9	9.3	10.2	7.7
Prairies	10.9	9.0	6.7	14.4	10.6	10.2	11.4
B.C.	0.4	0.6	0.5	0.7	0.7	0.6	0.6
Total	**24.2**	**18.7**	**18.6**	**26.0**	**20.7**	**21.0**	**19.7**
Other (including partially processed)							
Atlantic	0.3	0	1.2	0.2	0	0.3	0
Quebec	0.9	0	0.2	0	0	0.1	0
Ontario	3.4	3.4	5.3	4.6	4.8	4.5	4.9
Prairies	3.2	3.6	6.1	3.6	2.3	3.9	3.8
B.C.	5.4	5.5	4.0	3.5	3.5	4.1	3.3
Total	**13.2**	**12.5**	**16.8**	**11.9**	**10.6**	**12.9**	**12.0**
Total Domestic Receipts							
Atlantic	0.7	0	1.2	0.2	0	0.3	0
Quebec	12.9	4.9	3.3	2.6	0.1	0.1	0
Ontario	76.7	69.1	72.9	75.1	77.1	73.6	73.8
Prairies	64.3	57.7	58.8	65.9	60.6	60.8	58.4
B.C.	23.9	24.2	21.0	24.5	24.6	23.5	23.8
Total	**178.5**	**155.9**	**157.2**	**168.3**	**162.4**	**158.3**	**156.0**
B. Crude Oil Imports							
Atlantic	48.4	50.7	37.6	56.3	54.2	49.7	45.2
Quebec	35.1	39.6	35.7	44.2	47.8	41.9	43.5
Ontario	2.8	0.6	0.4	0.5	0.1	0.4	0.2
Prairies	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	0	0
Total	**86.3**	**90.9**	**73.7**	**101.0**	**102.1**	**92.0**	**88 .9**
C. Total Receipts							
Atlantic	49.1	50.7	38.8	56.5	54.2	50.0	45.2
Quebec	48.0	44.5	39.0	46.8	47.9	42.0	43.5
Ontario	79.5	69.7	73.3	75.6	77.2	74.0	74.1
Prairies	64.3	57.7	58.8	65.9	60.6	60.8	58.4
B.C.	23.9	24.2	21.0	24.5	24.6	23.5	23.8
Total	**264.8**	**246.8**	**230.9**	**269.3**	**264.5**	**250.3**	**245.0**

Appendix VI
International and Domestic Crude Oil Prices
(US$/bbl)

A.	AT SOURCE		Canadian Par	WTI NYMEX	Brent
	1990	Ave.	23.73	24.49	23.87
	1991	1Q	20.72	21.81	20.95
		2Q	19.73	20.77	18.94
		3Q	20.52	21.65	19.90
		4Q	20.63	21.77	20.59
		Ave.	20.40	21.50	20.09
	1992	1Q	17.87	18.92	17.96

B.	AT CHICAGO		Canadian Par	WTI NYMEX	Brent
	1990	Ave.	25.00	25.09	25.70
	1991	1Q	22.01	22.41	23.22
		2Q	21.01	21.37	20.93
		3Q	21.81	22.25	21.90
		4Q	21.92	22.36	22.42
		Ave.	21.69	22.09	22.11
	1992	1Q	18.98	19.52	19.59

C.	AT MONTREAL		Canadian Par	Brent
	1990	Ave.	25.21	25.61
	1991	1Q	22.29	22.88
		2Q	21.30	20.59
		3Q	(1)	21.47
		4Q	-	22.07
		Ave.	-	21.74
	1992	1Q	-	19.38

(1) the last delivery of domestic crude to Montreal via the Sarnia - Montreal pipeline was reported in July of 1991

Appendix VII
Average Regular Unleaded Gasoline Prices
(Self-Serve)
1991-1992

	1991				1992
	March 26	**June 25**	**Sept. 24**	**Dec. 31**	**Mar. 31**
	cents per litre				
St John's (NFLD)	62.0	61.8	61.8	61.8	60.9
Charlottetown	65.6	60.3	60.6	61.1	60.3
Halifax *	61.7	60.3	60.2	59.9	59.0
Saint John (N.B.) *	57.7	57.7	60.0	60.0	56.8
Montreal	63.0	63.2	66.5	63.8	59.0
Toronto	54.8	57.5	57.9	47.7	49.6
Winnipeg	49.0	47.2	53.8	49.8	46.8
Regina	49.9	38.9	42.9	50.9	41.9
Calgary	42.0	47.6	50.5	49.2	42.5
Vancouver	55.4	53.2	49.9	49.6	55.9
Average	**55.6**	**56.1**	**57.7**	**53.7**	**52.4**
Consumption taxes inlcude:					
Federal	12.0	12.1	12.2	11.9	11.9
Provincial	11.6	12.9	13.1	13.1	13.8

* *Full-Serve*

Appendix VIII
Consumption Taxes on Petroleum Products
(March 1992)

	Ad valorem		Gasoline			Diesel
	Mogas	Diesel	Reg UL	Mid UL	Prem UL	
	----------%----------		------------------ (cents per litre)			--------------
Federal Taxes						
Estimated GST (7%)			3.4	3.7	3.9	3.3
Excise			8.5	8.5	8.5	4.0
Provincial Taxes						
Newfoundland [a]	23	27	13.7	13.7	13.7	15.6
Prince Edward Island	23	26	11.8	11.8	11.8	11.8
Nova Scotia	24.5	31.5	12.6	12.6	12.6	14.2
New Brunswick			12.7	12.7	12.7	13.7
Quebec [b]			14.5	14.5	14.5	14.5
Ontario			14.7	14.7	14.7	14.3
Manitoba			10.5	10.5	10.5	10.9
Saskatchewan			10.0	10.0	10.0	10.0
Alberta			9.0	9.0	9.0	9.0
British Columbia [c]	22.5	(d)	9.76	9.76	9.76	10.2
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	(e)	9.4	9.4	9.4	8.0

(a) The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay, Labrador.

(b) Reduced by varying amounts in certain remote areas and within 20 kilometres of the provincial and U.S. borders.

(c) Additional transit tax of 3.0 cents per litre in Vancouver.

(d) The tax on diesel 0.44 cents per litre higher than the unleaded tax.

(e) 85% of gasoline tax.

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional area	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude Oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydro carbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Synthetic crude oil	Crude oil production treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

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The Canadian Oil Market

Vol VIII, No. 2, Summer 1992

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The Canadian Oil Market

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Canadian Oil Markets and Emergency Planning Division
Energy Sector
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The Canadian Oil Market

Overview

This issue of the Canadian Oil Market reviews Canadian oil supply and demand developments in the second quarter of 1992.

Highlights

- Petroleum product sales increased during the second quarter of 1992 as a result of a slight improvement in the economy.
- The Canadian Petroleum Association (CPA) reports that reserves of relatively cheap to produce conventional crude oil have fallen about 40% since 1979.
- On June 5, 1992 crude oil began to flow from Canada's first commercial offshore development located off the coast of Nova Scotia.
- The Alberta Petroleum Marketing Commission (APMC) announced plans to deliver crude oil to Montreal via IPL's deactivated Sarnia-Montreal pipeline.
- Relatively low refinery throughput reflected seasonal refinery turnarounds and weak refined product markets.
- Domestic crude oil prices began to strengthen as a result of OPEC production quotas.

This issue also contains a review of the second quarter and first half 1992 financial performance of the Canadian oil and gas industry prepared by the *Petroleum Monitoring and Information Services Division.*

The Canadian Oil Market

1. Refined Petroleum Product Consumption

*. **Demand for refined petroleum products, like the economy showed only weak signs of recovery.***

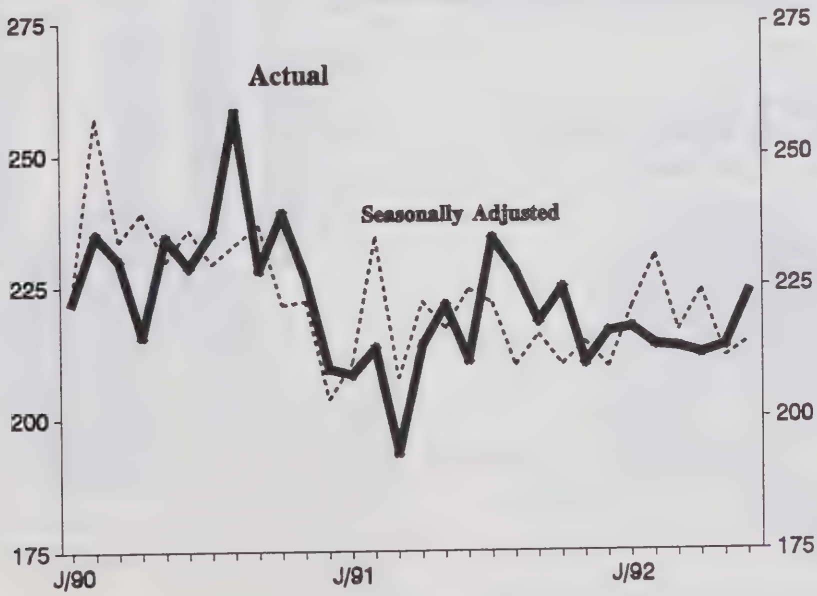
Total petroleum product sales during the first half of 1992 averaged 215 000 m^3/d. A slight improvement in the economy helped to push sales up about 5 000 m^3/d or 3% above a year earlier. However, sales remained 12 000 m^3/d or 5% below that recorded during the same period in 1990.

Motor gasoline which accounted for about 40% of total product sales during the first six months of the year increased by 2% to 88 000 m^3/d. While heavy fuel oil, albeit on small volumes, jumped 12% to 24 000 m^3/d, sales of middle distillates and 'other' refined products including jet fuels, asphalt, lubes and petrochemical feedstocks remained relatively unchanged from a year earlier.

Second quarter product sales averaged 216 000 m^3/d, up about 1% or 1 000 m^3/d from a year earlier. In June, product sales jumped about 5% or 10 000 m^3/d above the previous month to nearly 224 000 m^3/d. This increase was led by a sudden surge in motor gasoline and 'other' products sales.

All regions experienced higher sales during the first half of the year. The Atlantic region recorded the largest increase with sales up 10% from a year earlier to nearly 33 000 m^3/d. This increase was primarily the result of significant rise in demand for heavy fuel oil used for the most part to generate electricity. Sales in Quebec were up 1% to 46 000 m^3/d while in Ontario sales increased 3% to 72 000 m^3/d. Sales in the Prairies and British Columbia averaging 41 000 m^3/d and 25 000 m^3/d, improved slightly.

Figure 1.1
Refined Petroleum Product Sales
000 m^3/d



2. Drilling and Exploration Activity

. The slump in oil drilling in western Canada is likely to continue into 1993 as producers cut back on exploration programs.

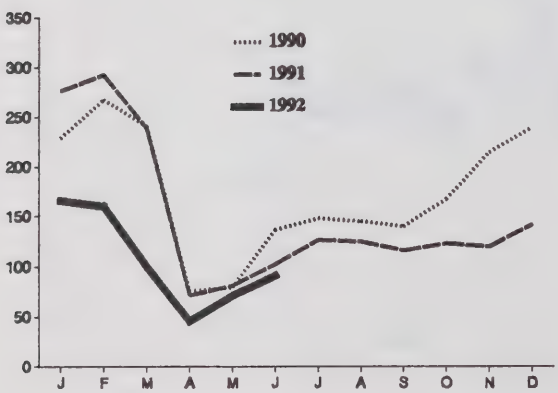
. Reserves of conventional crude oil continue to decline as additions to reserves fail to replace production.

2.1 Drilling Activity

The drilling industry in western Canada is experiencing its worst year since the early 1970's. Despite firming oil and gas prices and falling interest rates, drilling activity during the first half of 1992 fell short of industry expectations. Only 106 or 24 % of 437 drilling rigs were reported active compared with an average 176 or 36% of 476 a year earlier. Second quarter activity averaged 17%.

Alberta's attempt to stir drilling by the temporary suspension of royalties on new and reactivated oil wells proved disappointing. With only 17% of Alberta's rig fleet active during the first half, the hard-pressed industry is again calling for a review and reduction in provincial royalties and a more permanent status for the ARTC (Alberta Royalty Tax Credit Program). The ARTC has been used on a short-term basis to reduce royalties on production up to a maximum volume.

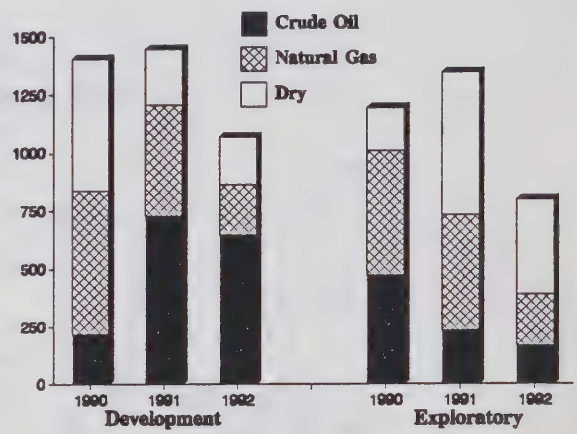
Figure 2.1.1
Drilling Activity in Western Canada
(Number of Wells)



There were 33% less crude oil and natural gas wells completed in western Canada during the first half of 1992 compared with a year earlier. By the end of June about 1870 wells had been completed of which nearly one third proved dry. Metres drilled fell 27% to about 2.6 million metres. However, the average depth per well increased by about 7% largely due to the emergence of horizontal drilling, particularly encouraged by the government of Saskatchewan.

So far this year, oil and gas exploratory drilling has taken a back seat to development activity. Exploration activity representing about 43% of western Canada's first half well completions fell by 25%. Natural gas recorded the largest drop, down 55% from a year earlier primarily as a result of market limitations. Company cut-backs in exploration programs prompted many producers to concentrate on lower-risk oil development projects.

Figure 2.1.2
Well Completions
(End-of-June)



The already depressed drilling industry in western Canada is expected to remain weak in 1992. Despite a modest rise in oil and natural gas prices, the CAODC expects less than 25% of available rigs to be active over the year. About 4 100 wells are expected to be completed - a significant drop from 1985's peak of about 12 100 wells.

2.2 Crude Oil Reserves

The CPA (Canadian Petroleum Association) in its annual estimate of Canada's hydrocarbon reserves, reports that end-1991 reserves of crude oil and equivalent have increased by almost 4% to 1 465.6 million m^3 (9.2 billion bbl) since end-1979. However, reserves of relatively cheap to produce conventional crude oil have been on the decline.

According to CPA data, since the end of 1979, reserves of conventional crude oil from producing fields have fallen about 40% to 648.7 million m^3 (4.1 billion bbl), with additions to reserves replacing only 32% of 1991 production. In Alberta, additions were equal to only 23% of its 1991 production.

There are another 192.6 million m^3 (1.2 billion bbl) of crude oil reserves in the frontier areas of Canada including the large 138.6 million m^3 (872 million bbl) Hibernia field of Newfoundland, which is not expected to come on stream before 1997. An additional 53 million m^3 (340 million bbl) is located in the Mackenzie/Beaufort area.

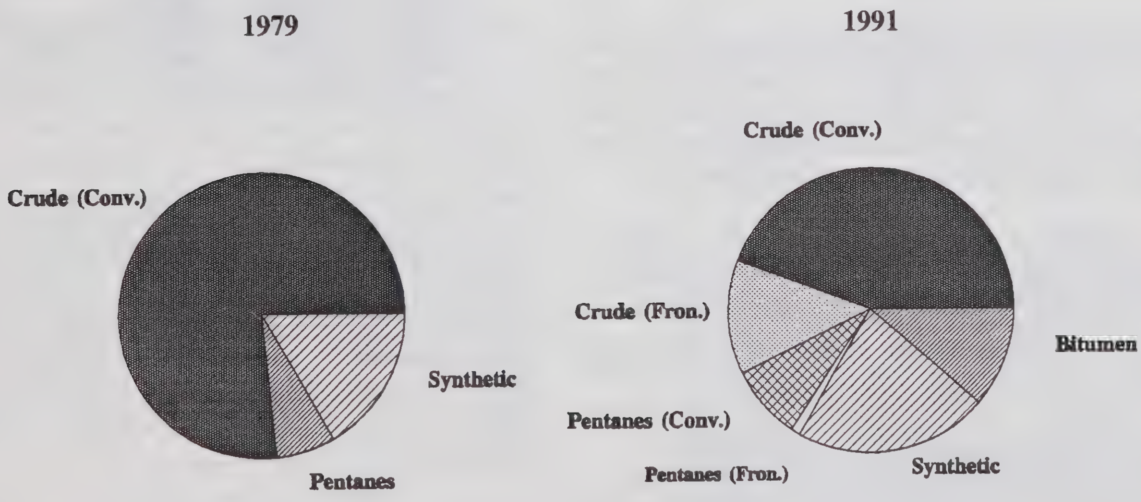
Developed reserves for the Syncrude and Suncor oil sands plants increased by 2% to 320.7 million m^3 (2.0 billion bbl) primarily as a result of rise in productive capacity. However, reserves of developed in-situ bitumen dropped nearly 6% to 164.3 million m^3 (1 034 billion bbl) as high cost projects were mothballed.

CPA data illustrates a significant shift away from conventional reserves to higher cost frontier and bitumen reserves. By the end of 1979, conventional reserves of crude oil and pentanes accounted for about 80% of total proven reserves. This compares with about 50% by the end of 1991.

The National Energy Board suggests that there is considerable uncertainty in the development of these high cost reserves. These reserves while technically feasible to develop are particularly price sensitive and would probably require prices in the US$25 to $35/bbl range to become economically feasible.

Analysts suggest that there may be more conventional crude left in western Canada but development would probably require the use of expensive new exploration and enhanced recovery techniques.

Figure 2.2
Crude Oil and Equivalent Reserves
(Year End)



3. Crude Oil Supply

. On June 5, crude oil began to flow from Canada's first commercial offshore well at a rate of 2 000 m³/d. The Panuke field is located 250 kilometres off Halifax, Nova Scotia.

. Imports rose 13% year-over-year during the second quarter. Part of the increase reflected the deactivation of the Sarnia-Montreal pipeline and hence the total reliance on foreign crude feedstocks in Montreal.

3.1 Total Supply

Total crude supply in the first half of 1992 averaged 357 000 m³/d. Supply over the second quarter of the year averaged 345 000 m³/d, compared with 337 000 m³/d a year earlier. The equivalent of 129 000 m³/d of this volume was delivered to the export market.

Second quarter domestic supply (including production from Ontario, Bent Horn and offshore Nova Scotia, plus surplus NewGrade supply, recycled diluent and inventory change) averaged 262 000 m³/d. Gross imports averaged 83 000 m³/d.

3.2 Domestic Production

Domestic crude oil production during the second quarter of 1992 reached 263 000 m³/d, 3% or 8 000 m³/d higher than a year earlier. Most of this increase was the result of a significant recovery in heavy crude production from a slump which occurred last year.

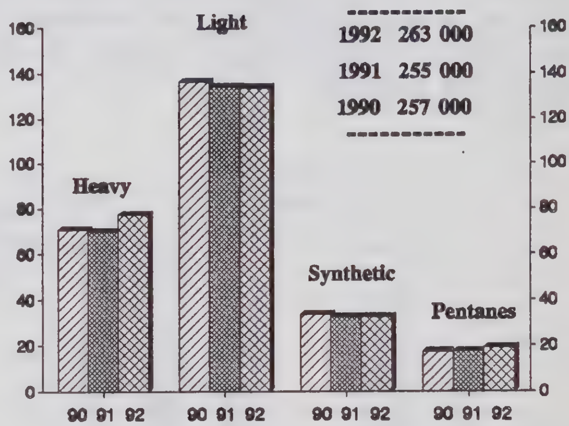
Over the quarter conventional light crude production averaged 134 000 m³/d. Although marginally below a year earlier, production was down nearly 5 000 m³/d from the previous quarter. Most of the decline occurred in Alberta where production fell to nearly 109 000 m³/d.

The slide in conventional light crude oil production from western Canada is expected to be offset by new production from the Panuke/Cohasset fields located 250 kilometres off Nova Scotia and greater supply from Bent Horn in the North West Territories. Including this year's estimated 50 000 m³, Bent Horn has delivered to Montreal about 300 000 m³ since it first began operating in 1985.

Canada's first commercial offshore oil field began operation on June 5, with production from the Panuke oil field averaging about 2 000 m³/d. Production is expected to increase to about 3 500 m³/d by the end of November before operations cease for the winter season. Production will resume in the spring of 1993 at which time the Cohasset field will also be brought on stream. This will result in a combined offshore production of about 6 400 m³/d.

Figure 3.2
Domestic Crude Oil Production
(Second Quarter)

000 m³/d



The first shipment of about 80 000 m³ of high quality crude oil from Panuke is expected to arrive in Mobile, Alabama by early July. Scotian light reportedly commands a premium on prices quoted for light, sweet crudes on the New York Mercantile Exchange. This is the first of several deliveries of approximately the same size scheduled to be delivered to eastern Canada and U.S. markets this year.

Second quarter supply of synthetic crude oil proved to be less than expected. Although slightly below the previous year at 33 000 m³/d, production was down about 5 000 m³/d below the previous quarter. A fire at

one of Suncor's hydrotreating plants in April reduced output by about 4 000 m³/d to 7 000 m³/d. This drop was exacerbated by seasonal maintenance and turnaround at the Syncrude oil sands plant which over the quarter produced about 26 000 m³/d of synthetic crude.

Conventional heavy (unblended) crude oil production recovered from the post Gulf war slump. Second quarter production increased by 5 000 m³/d to 56 000 m³/d. Bitumen output at 22 000 m³/d was 2 000 m³/d higher than a year earlier.

Heavy crude oil production increased primarily as a result of the May 1 start up of deliveries to the Conoco refinery in Billings, Montana. This refinery is expected to process about 6 000 m³/d of Canadian heavy crude by early summer. As well, the Husky Bi-provincial upgrader which is expected to process about 7 000 m³/d crude by November started to accept deliveries of heavy crude in April for plant capitalization runs.

Higher demand for heavy crude was offset somewhat by limited deliveries to the Newgrade refinery over the latter part of the quarter when the refinery was closed for annual maintenance.

The National Energy Board (NEB) expects total domestic production to average 270 000 m³/d in 1992, compared to 264 000 m³/d in 1991.

3.3 Crude Oil Imports

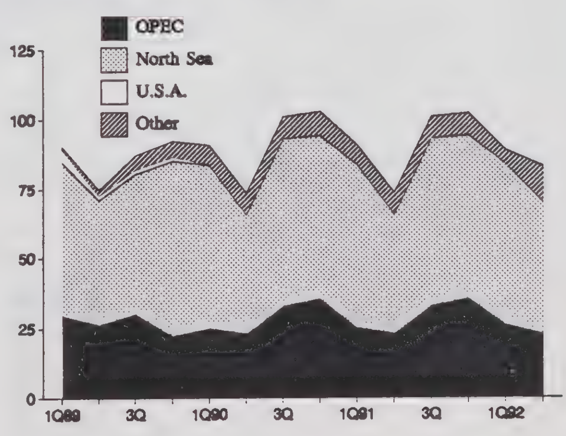
Refineries in eastern Canada imported about 83 000 m³/d of crude (and partially processed) oil during the second quarter of 1992. This was almost 10 000 m³/d higher than during the same period last year. Virtually all of the imports were destined for the refineries in the Atlantic and Quebec regions, two regions which have become almost exclusively dependent on foreign crude feedstocks. In Ontario, imports continued to account for only a very small fraction of refinery crude oil receipts, remaining below the 1 000 m ³/d level. From a national perspective, imports corresponded to about 38% of the total volume of crude delivered to Canadian refineries. It should be noted that partially processed oil now comprises about 10% of imports, up from about 2% as recently as 1990.

In the Atlantic region, imports climbed by almost 5 000 m³/d to over 42 000 m³/d. The increase led to a sizeable build of crude oil inventories in the region. Almost 45% of Atlantic imports consisted of North Sea production. OPEC accounted for another 45%, with Saudi Arabia, Nigeria and Venezuela, in that order, being the predominant sources of OPEC supply.

Imports into Quebec rose 4 000 m³/d to 40 000 m³/d. Last year during the second quarter, the purging of the Sarnia-Montreal extension got under way and was essentially completed by the end of the quarter. Montreal refiners thus continued to receive, albeit small volumes of western Canadian crude oil while the line was being emptied during the purging operation. The increase in imports this year reflected the deactivation of the extension and thus the total conversion from domestic to imported crude oil feedstocks by the Montreal refineries.

North Sea crudes accounted for over 70% of Quebec imports, while OPEC's share was about 10%. Prior to the closure of the extension, Quebec refiners typically processed about 4 000 m³/d of heavy crude oil from western Canada, mainly to produce asphalt. After its closure, Quebec refiners turned to Mexican heavy crudes for asphalt production. Imports from Mexico rose commensurately, accounting for almost a 15% share of the Quebec total during the second quarter.

Figure 3.3
Imports of Crude Oil by Source
000 ³/d



4. Crude Oil Disposition

. Reflecting the general malaise in the Canadian economy, the refining industry remained in a slump during the second quarter, despite a small year-over-year increase in crude oil receipts.

. High exports to the United States helped to offset weak recession-driven demand for indigenous crudes.

4.1 Canadian Refinery Crude Oil Receipts

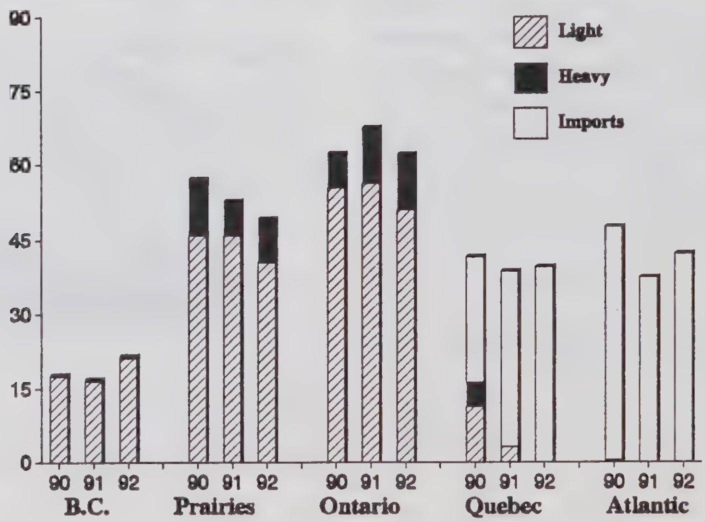
The slump in the Canadian refining industry persisted in the second quarter of 1992. This was reflected in the sluggish demand for crude oil by domestic refiners during this period. This sluggishness is expected to continue for the remainder of 1992 with crude oil demand averaging in the 225 000 m^3/d range for the year. This would amount to a drop of about 15 000 m^3/d from last year's annual average, and of about 25 000 m^3/d from the year before.

Although crude oil demand was marginally higher year-over-year during the second quarter, demand remained about 10% below its pre-recessionary peak. This decline was consistent with the stalled recovery in refined product sales in the Canadian market. Crude oil demand was further reduced by a relatively large number of spring turnarounds this year which helped push crude runs to their lowest level in the last 5 years.

Averaging 216 000 m^3/d during the second quarter, crude oil deliveries to domestic refiners were only about 2 000 m^3/d or less than 1% higher than last year. Although there were fairly significant increases in crude oil receipts in the Atlantic region and British Columbia, these were largely offset by declines in central Canada and the Prairies. The increase in the Atlantic led to a substantial build of crude oil inventories. In British Columbia, a downward trend in crude oil deliveries has been reversed within the last year as a result of one refinery reactivating its catalyctic cracker and another undertaking a small expansion in capacity.

A rise of over 9 000 m^3/d in crude oil imports (to 83 000 m^3/d) into eastern Canada more than offset a 7 000 m^3/d drop in receipts of domestic crude oil. Except for minimal deliveries of U.S. crude to Ontario, refineries west of Quebec met all their crude oil feedstock requirements from western Canadian production. Deliveries of domestic crude oil averaged 133 000 m^3/d, accounting for 62% of total refinery crude oil receipts. Although receipts of domestic heavy crudes rose slightly from last year, demand for light crudes dropped by 9 000 m^3/d. This year's decline in domestic crude deliveries reflected both the recession and the closure of the Sarnia-Montreal extension in July of 1991.

Figure 4.1
Refinery Crude Oil Receipts
(Second Quarter)
000 m^3/d



4.2 Crude Oil Exports

Crude oil exports during the second quarter of 1992 averaged 129 000 m^3/d, 7% or 8 000 m^3/d more than a year earlier. Most of the increase was caused by a decline in domestic demand for indigenous light crude oils and the closure of the Sarnia to Montreal portion of the Interprovincial Pipe Line.

Second quarter exports of light crude oil averaged 73 000 m^3/d. Exports were 19% or 12 000 m^3/d higher than a year earlier. This jump offset a 6% or 4 000 m^3/d decline in heavy crude oil deliveries which over the quarter averaged 56 000 m^3/d.

Most exports ~~were~~ are delivered to the United States with about 78% of this volume delivered to the U.S. midwest (PAD District II). Relatively small volumes of light crude were tankered off the west coast to Pacific Rim destinations.

PAD District II received 100 000 m^3/d of Canadian crude oil, up 38 % from a year earlier. Deliveries of light crude increased by 22% to 52 000 m^3/d while heavy receipts fell by 10% to 48 000 m^3/d. All other U.S. destinations, including Canada's second largest market, PAD District IV (the Montana/Wyoming area), increased their deliveries modestly.

Total exports during the second quarter of 1992 represented about 49% of production (61% of blended heavy supply and 43% of net light crude oil). This compares with 47% a year earlier. Exports of crude oil exceeded crude imports by about 46 000 m^3/d. This compares with 47 000 m^3/d a year earlier.

Crude oil exports are expected to average 130 000 m^3/d over 1992. At this level, exports would be substantially above that recorded over the last few years with light crude exports accounting for much of this strength.

Figure 4.2
Crude Oil Exports
000 m^3/d

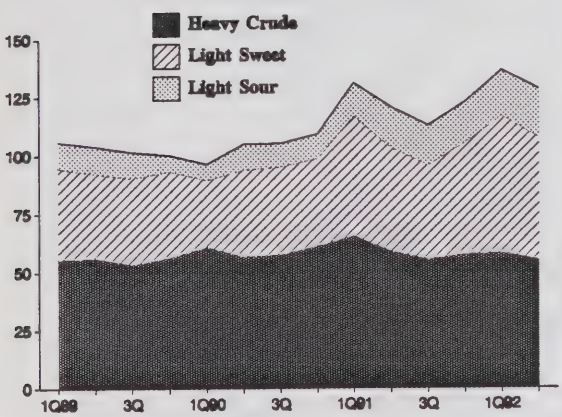
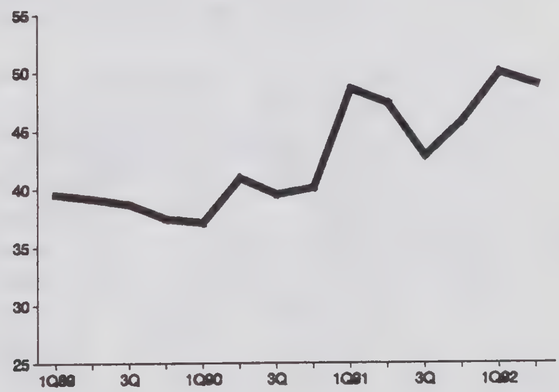


Figure 4.2.2
Crude Oil Exports
Percentage of Production



5. Pipeline Deliveries

. Reduced demand for light crude oil in eastern Canada resulted in a significant increase in deliveries to the Vancouver area and offshore.

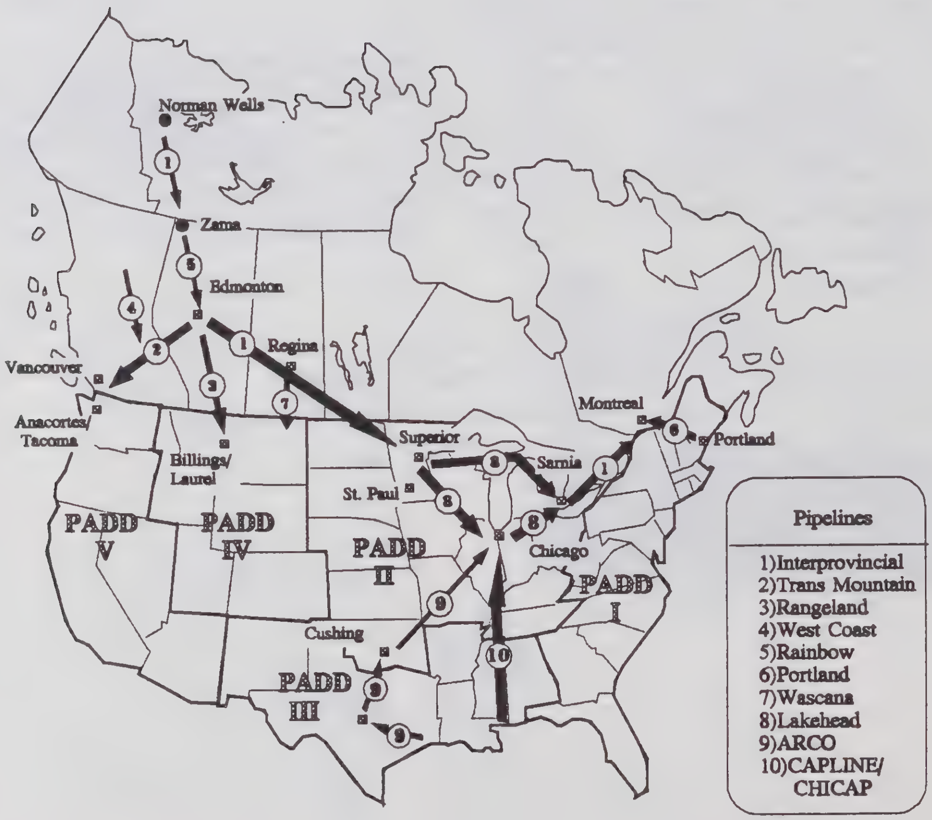
. Although the Sarnia-Montreal extension remained idle during the second quarter, IPL reactivated the line in early July to permit western producers to resume crude oil deliveries to Montreal.

Most Canadian crude oil is gathered at Edmonton Alberta. It is then delivered to the domestic and export market, for the most part, by a network of pipelines.

The bulk of Canadian crude exports are delivered to the United States via the Interprovincial and Lakehead pipeline system. Smaller volumes are delivered by the Trans Mountain Pipe Line to the west coast for delivery to large U.S. refineries in the Puget Sound area and for tankering offshore. The Rangeland pipeline carries crude oil south into Montana.

Canadian crude oil delivered to the U.S. midwest competes in the key Chicago refining area with U.S. domestic crudes and other foreign crudes delivered through the CAPLINE/CHICAP pipeline system from the Louisiana Gulf Coast and alternatively the Arco pipeline system from the Texas Gulf Coast via Cushing, Oklahoma.

Figure 5
Major Crude Oil Pipelines



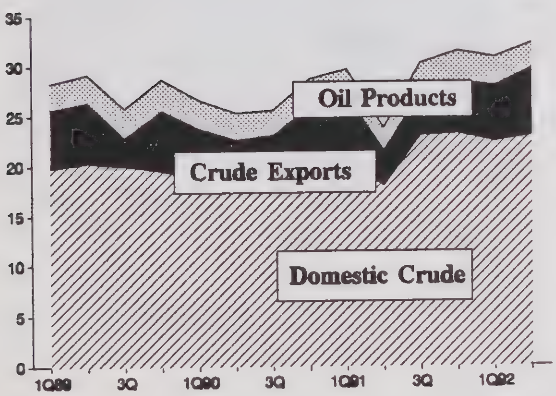
5.1 Trans Mountain Pipe Line Deliveries

The Trans Mountain Pipe Line (TMPL) originates at Edmonton and delivers crude oil, semi-refined and refined petroleum products some 1328 kilometres west to the Vancouver area. The pipeline also receives crude from northern British Columbia at Kamloops delivered via the West Coast Pipe Line.

Total deliveries during the second quarter of 1992 averaged 32 000 m^3/d, up 8 000 m^3/d from a year earlier. Domestic deliveries totalled 25 000 m^3/d of which 23 000 m^3/d (90% crude) was delivered to the Vancouver/Burnaby area. The remainder composed of refined petroleum products was delivered to Kamloops, British Columbia.

Crude oil deliveries for export averaged 7 000 m^3/d, up about 3 000 m^3/d from a year earlier. About 5 000 m^3/d of primarily light crude was tankered offshore via TMPL's Westridge Marine Terminal with the remainder delivered by pipeline to refiners in the Puget Sound area of Washington state.

Figure 5.1
Trans Mountain Deliveries
000 m^3/d



5.2 Interprovincial Pipe Line Deliveries

The Interprovincial Pipe Line (IPL) system consists of three major sections stretching some 3 700 kilometres from western Canada east to Montreal, Quebec. The western section of the IPL originates at Edmonton and travels east through Regina, Saskatchewan and crosses into the United States near Gretna, Manitoba. The Lakehead Pipe Line manages the pipeline which serves the U.S. Great Lakes region via routes to the north and south of Lake Michigan to Sarnia.

IPL deliveries during the second quarter of 1992 averaged 221 000 m^3/d. This compares with 226 000 m^3/d the year before. U.S. markets received 114 000 m^3/d with shipments to Ontario down 4% to 79 000 m^3/d. With the closure of IPL's Sarnia-Montreal extension in July, 1991, Quebec became almost entirely dependent upon foreign crude.

Deliveries on the Sarnia-Montreal pipeline began to decline late in 1990 from nearly 20 000 m^3/d early in the year to about 5 000 m^3/d by year end. Citing increasing competitiveness of offshore crudes in Montreal, shippers advised IPL that they intended to terminate domestic crude deliveries during the first quarter of 1991. As a result, IPL deactivated the line which at its peak in 1979/1980 delivered nearly 50 000 m^3/d to the Montreal refineries.

After weighing the arguments put forward by intervenors at the Class 3 Toll Hearings last winter, the National Energy Board (NEB) announced in June that stand alone tolls were appropriate for an idle or reversed Sarnia-Montreal extension. The new toll design was to be retroactive to the beginning of 1992, replacing an integrated toll design that had been in place since 1984. The extension's tolls were now to be calculated strictly on the basis of those fixed and variable costs identified with the extension. Previously, these costs had been integrated for tolling purposes with those of IPL's older pipeline system (which extends from Edmonton to Toronto).

A few weeks prior to the release of the NEB's decisions, the Alberta Petroleum Marketing Commission (APMC), which markets royalty crude for the Alberta government, announced its intension to resume deliveries to Montreal. It proposed to deliver between 3 000 and 5 000 m^3/d of conventional light crude oil to Montreal for a period of about a year, with linefill injections starting in early July. More recently, APMC has indicated that these deliveries could continue over the entire year of 1993. Because filling the 365 000 m^3 pipeline with crude oil will take several months to complete, it is not expected that the oil will actually reach Montreal until sometime in 1993.

APMC's plan to re-open the Montreal market to western Canadian crude oil production is expected to improve netbacks for producers by reducing the pressure to sell their crudes into the important Chicago market. For this reason it received broad support from the upstream sector. The NEB was requested to re-approve integrated tolls so that the incremental pipeline transportation costs to Montreal would be borne by the Canadian upstream sector in general, not just the APMC. The NEB agreed to re-establish integrated tolls in July, only because the extension would once again be operating in a west-to-east mode. The Alberta government is also intending to raise oil royalties to cover APMC's linefill carrying costs, and any discounts and transhipment costs required to displace imports in or beyond the Montreal market.

Figure 5.2.1
IPL Deliveries
000 m^3/d

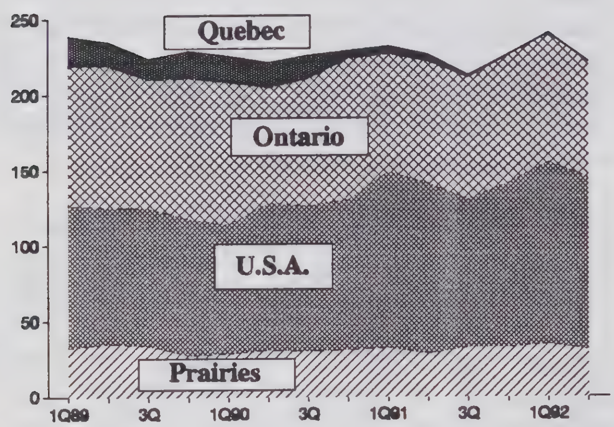
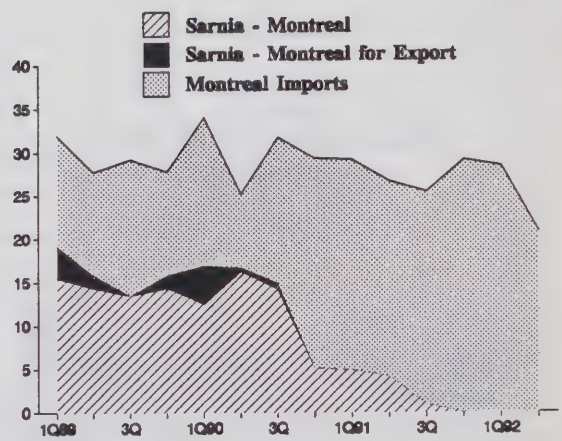


Figure 5.2.2
Deliveries to Montreal
000 m^3/d

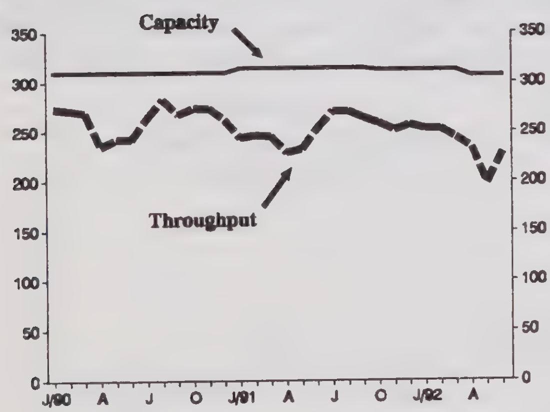


6. Refinery Activity

. The national refinery utilization rate for the second quarter of 1992 averaged 72%. This relatively low rate reflected a large number of refinery turnarounds during the quarter and depressed refined product markets.

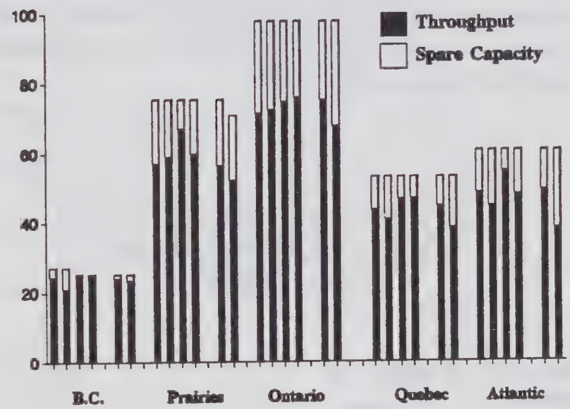
Refinery throughput will normally diverge from refinery crude oil receipts for two reasons. First, feedstocks other than crude oil are also charged in the refining process. Some of the 'other' feedstocks include gas plant butanes (used mostly by Prairie refineries) and partially processed oil (used mostly by B.C. refineries). During the second quarter of 1992, these 'other' receipts averaged a little below 8 000 m^3/d accounting for about 3% of total refinery feedstock receipts in Canada. Second, refinery throughput reflects changes in feedstock inventories. Other things being equal, an inventory drawdown will cause refinery throughput to exceed receipts - and vice versa in the case of an inventory build. Over the quarter, crude oil inventories at the national level were built at a rate of almost 4 000 m^3/d.

Figure 6.1
Total Capacity and Utilization
000 m^3/d



Total throughput averaged 220 000 m^3/d during the second quarter, about 18 000 m^3/d below the same quarter last year. With Canadian refining capacity estimated to have fallen to about 307 000 m^3/d, this level of throughput corresponded to a national refinery utilization rate of about 72%. The utilization rate was highest in British Columbia where it approached nameplate capacity, and lowest in the Atlantic region where it fell to just 63%. Although refiners expect to refining activity to pick up somewhat in the latter half of 1992, crude runs will still remain significantly below pre-recessionary levels.

Figure 6.2
Regional Capacity and Utilization
(1stQuarter 1991 to 2nd Quarter 1992)
000 m^3/d



Reflecting the slump in refined product sales and excess refining capacity the Prairies, the Turbo refinery located near Calgary was shut down permanently mid-way through the second quarter. The 4 500 m^3/d refinery began operations in 1982 and was largely dedicated to producing transportation fuels from conventional light crude oil. The refinery closure was part of a rationalization process initiated by Pay Less Holdings Inc. after it had acquired Turbo Resources Ltd. in early May.

7. Crude Oil and Petroleum Product Stocks

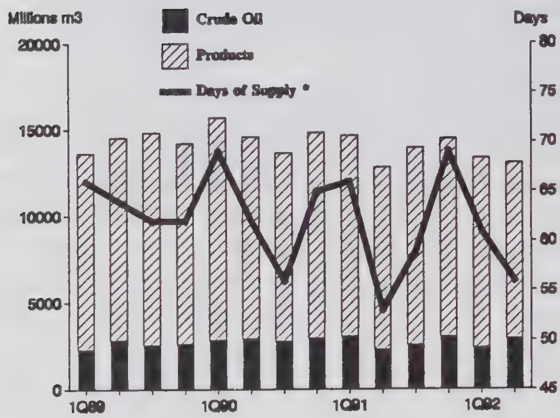
. Stocks of refined petroleum products remained low due to the continuing slump in product demand.

Primary stocks of crude oil and refined petroleum products closed the second quarter of 1992 at 13.1 million m^3. Stocks were up 2% or 276 000 m^3 from that recorded a year earlier.

Of this volume, second quarter refined petroleum product stocks at 10.2 million m^3 were down 3% or 356 000 m^3 from a year earlier. Crude oil stocks, on relatively small volumes, were up 28% or 632 000 m^3 to 2.9 million m^3.

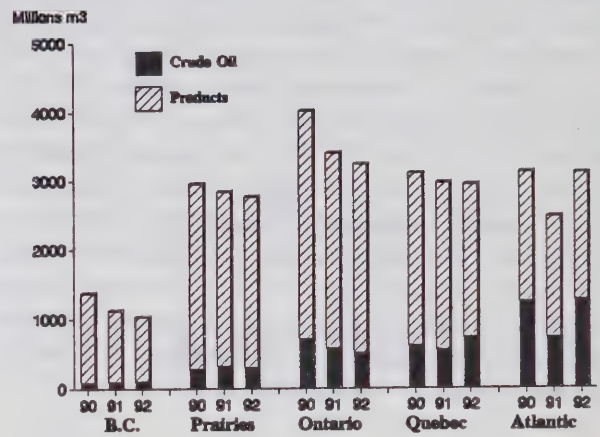
Most of the decline in refined petroleum product stocks reflected the recession-driven drop in demand. Stocks of crude, although higher than a year earlier, remained within normal operating levels.

Figure 7.1
Crude and Product Stocks
(End-of-quarter)



Stocks of 'main' petroleum products, totalling 6.7 million m^3, were down 8% or 566 000 m^3 from the year before. An 11% or 471 000 m^3 drop in middle distillates to 3.8 million m^3 accounted for most of this decline. Stocks of motor gasoline were down 7% or 231 000 m^3 to 3.1 million m^3.

Figure 7.2
Crude and Product Stocks by Region
(End-of-quarter)



End-of-June crude oil and refined petroleum product stocks represented a reserve of about 56 days of supply (based on historical consumption). This compares with 53 days of supply a year earlier. Stocks of 'main' petroleum products fell to 38 days of supply from 40 days.

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* *Stocks do not include estimates of crude oil held in pipelines/tankage. If these stocks were to be included it is estimated that the number of days of supply would increase by about seven days.*

Figure 7.3
Total Petroleum Product Stocks
thousands m³

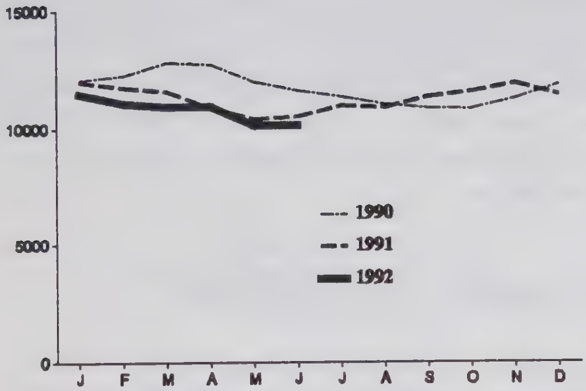


Figure 7.4
Motor Gasoline Stocks
thousands m³

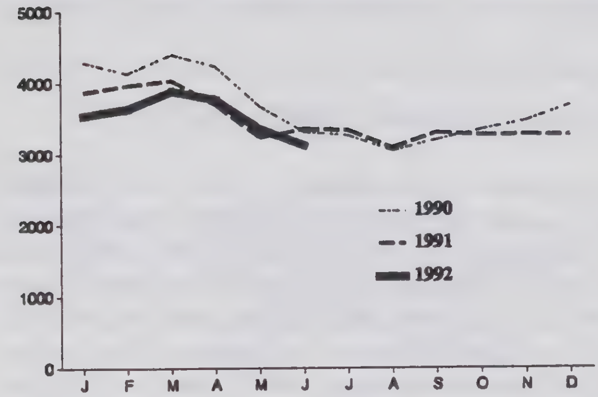


Figure 7.5
Light Fuel Oil Stocks
thousands m³

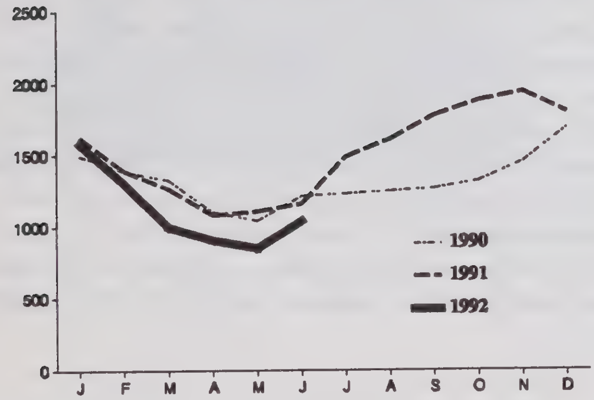


Figure 7.6
Diesel Fuel Oil Stocks
thousands m³

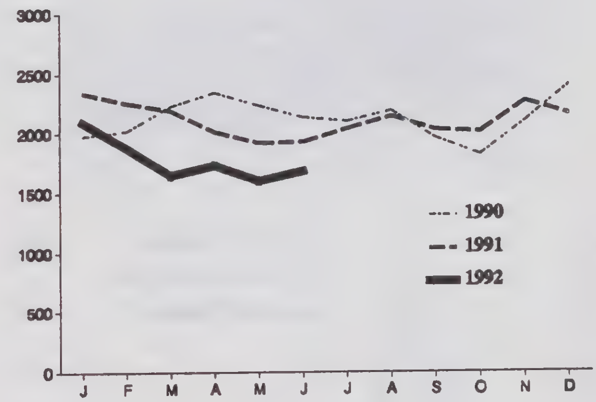


Figure 7.7
Heavy Fuel Oil Stocks
thousands m³

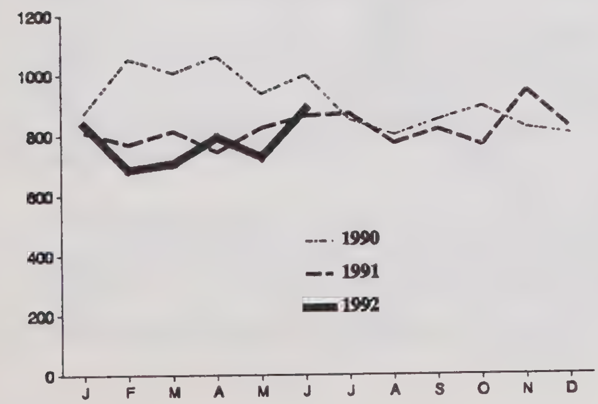
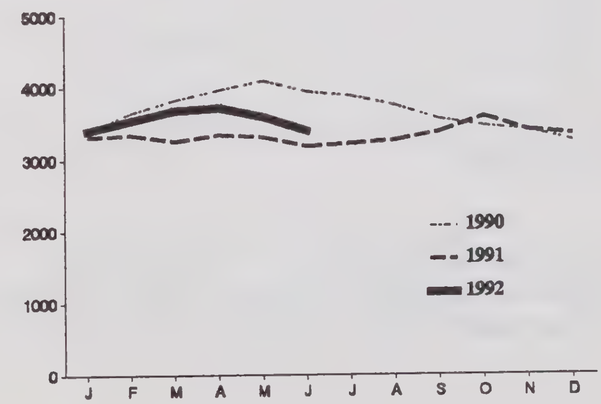


Figure 7.8
Other Petroleum Product Stocks
thousands m³



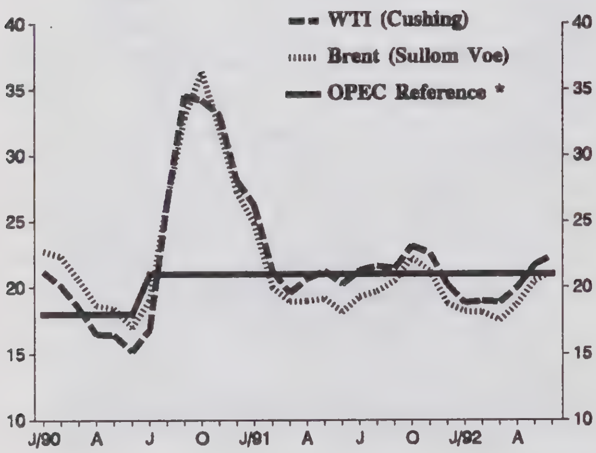
8. Crude Oil Prices

. International and domestic crude oil prices in the second quarter were affected by OPEC production quotas.

8.1 International Crude Oil Prices

Throughout the first quarter of 1992, weak oil supply and demand fundamentals translated into relatively sluggish crude oil prices. However, prices did begin to strengthen over the latter part of the quarter when OPEC members agreed to restrain crude oil production at 22.98 MMB/d during the March to June period. West Texas Intermediate (WTI) crude oil averaged $18.90 bbl in first quarter of 1992, a decrease of $3.35/bbl from high levels recorded during the Persian Gulf crisis early in 1991.

Figure 8.1
International Crude Oil Prices
US$/bbl



** OPEC's reference price for a basket of seven key OPEC crudes.*

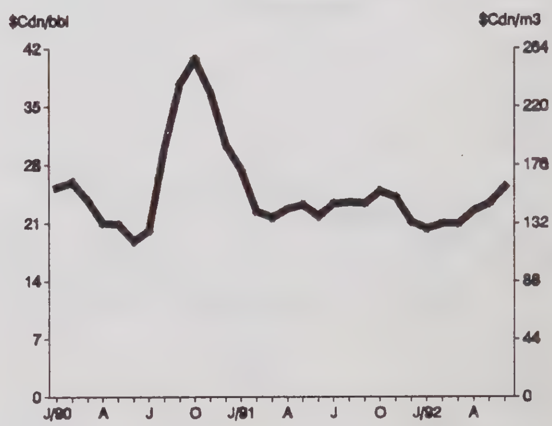
Over the second quarter of 1992, oil supply and demand fundamentals strengthened and crude oil prices moved steadily upwards. Oil prices were supported by the following: OECD commercial oil stocks in April 1, were at normal levels for the first time in almost two years; uncertainty surrounding an embargo against Libyan crude oil and the level of Russian crude oil production and exports; the continued absence of Iraqi crude oil from world oil markets; and the outlook for a strong recovery in the U.S. economy (driven by preliminary data indicating rising U.S. oil demand in April and May). Consequently, WTI averaged $21.10/bbl over the second quarter, up $2.20/bbl from a year earlier.

8.2 Domestic Crude Oil Prices

The price for Canadian Par crude oil (40° API, 0.5% sulphur), as posted by refiners, averaged $23.95/bbl ($150.75/m^3) in the second quarter of 1992. This price represents an increase of $3.15/bbl ($19.82/m^3) over the first quarter average.

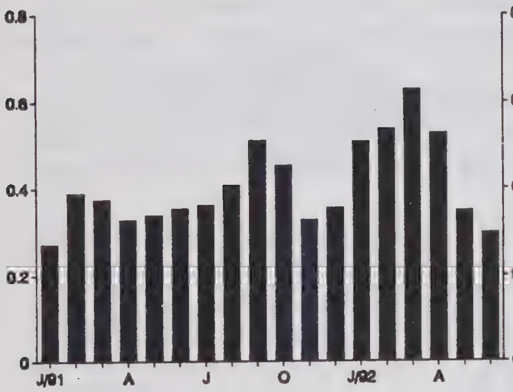
Canadian crude oil prices continue to follow the trends set in international markets. The price increase in the second quarter is primarily the result of the May OPEC meeting, where previous production quotas were rolled over into the third quarter. Other international factors, such as failed talks between Iraq and the UN security council to resume Iraqi exports, political developments in Algeria and tight North Sea supply, all combined to push prices higher. Closer to home, hydrostatic testing on the Interprovincial pipeline, which lasted longer than anticipated, further tightened supply in the northern U.S.

Figure 8.2.1
Canadian Par Crude Oil Postings



The differential between WTI and Canadian Par Crude at Chicago decreased in the second quarter of 1992 to an average US\$0.39 (\$2.45/m^3), compared to the first quarter average of US\$0.56/bbl (\$3.52/m^3). The decrease reflects a return to the more traditional levels experienced in 1991 and can be attributed to a general firming of supply and demand fundamentals in markets for Canadian crude oil.

Figure 8.2.2
Canadian Par vs WTI NYMEX
CDN$//bbl



8.3 Domestic Crude Oil Differentials

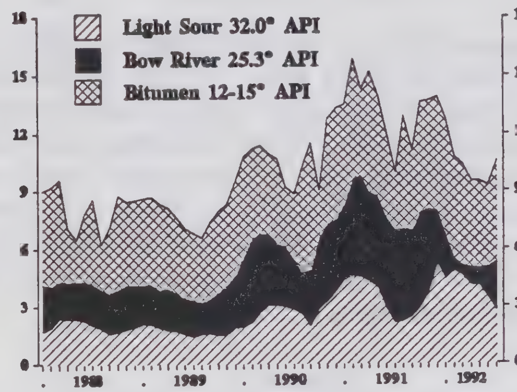
The following graph illustrates the crude oil price differentials between Canadian Par crude at Edmonton and the average posted price of Alberta Light Sour Blend, Bow River (heavy) and bitumen.

Domestic crude differentials in the second quarter of 1992, continued their downward trend to more traditional levels, and reflected the seasonal increase in demand for heavy crudes.

The differential between Par and Light Sour Blend averaged \$3.48/bbl (\$21.90/m^3) in the second quarter, a decrease of \$0.27/bbl (\$1.70/m^3) from the corresponding period a year earlier.

Over the same period the Par Bow differential fell by \$3.27/bbl (\$20.58/m^3) to \$5.16/bbl (\$32.47/m^3). Similarly, the Par to bitumen differential dropped to \$9.78/bbl (\$61.54/m^3), a decrease of \$3.93/bbl (\$24.86/m^3) over the second quarter of 1991.

Figure 8.3
Domestic Crude Oil Price Differentials
CDN$/bbl



9. Petroleum Product Prices

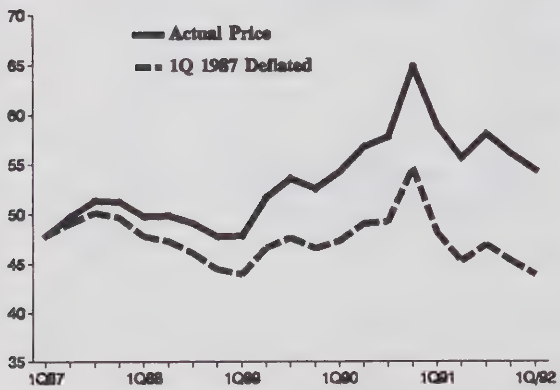
. The price spread between Canada and the United States narrowed again this quarter due to a decrease in crude costs in Canada. Taxes accounted for over 90% of the difference.

9.1 Price Trends

The average pump price of regular unleaded gasoline was 54.3 ¢/litre during the second quarter of 1992, an increase of 1 ¢ over the last quarter. Comparing the price for the first half of 1991 to the same period in 1992, prices went from 57.4 to 53.8 ¢/litre, a decrease of 3.6 ¢/litre.

The average price of regular unleaded gasoline in Canada went from 52.1 ¢/litre in March 1992 to 55.9 ¢/litre in June, an increase of 3.8 ¢/litre over the three months of the quarter. Prices in Montreal and in the Maritimes remained stable while there were large increases in Toronto, Winnipeg and Regina. Despite an increase of 4.1 ¢/litre over the second quarter, Regina's price of 46.9 ¢/litre in June remained the lowest of the major centres surveyed.

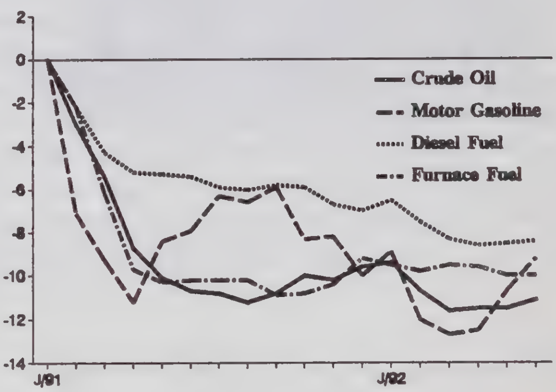
Figure 9.1
Regular Unleaded Gasoline Prices
cents per litre



In contrast to gasoline, the average diesel price in Canada declined by 1.5 ¢/litre from the first to the second quarter of 1992, going from 54.4 to 52.9 ¢/litre. The largest drops were in Montreal and Toronto, where prices decreased by 2.2 and 1.4 ¢/litre, respectively, during that period. Average furnace oil prices were virtually unchanged from the first quarter at about 38 ¢/litre.

The following graph shows the evolution of retail petroleum product prices since January 1991. In general, diesel and furnace fuel oil prices follow the trend set by crude oil prices. Between May and July 1991, motor gasoline prices increased contrary to the trend of crude oil prices. At the end of the Persian Gulf war, gasoline prices fell dramatically due to extremely high gasoline inventories and lower gasoline demand caused by the recession. As inventories fell and seasonal demand picked up with the onset of the tourist season, prices increased.

Figure 9.2
Cumulative Price Changes
(Since January 1991)
cents/litre



9.2 Consumption Taxes on Petroleum Products

The sum of federal and provincial taxes on regular unleaded gasoline was 26 ¢/litre in the second quarter of 1992, up 0.2 ¢/litre from the first quarter. Both federal and provincial average taxes increased 0.1 ¢/litre. At the federal level, higher gasoline prices brought about an increase in the Goods and Services Tax.

During the second quarter, provincial taxes decreased in the Maritimes because of their quarterly reviews or changes in their budgets. Budget changes were the reason for tax increases in both Saskatchewan (+3 ¢/litre) and British Columbia (+0.24 ¢/litre) during the same period.

9.3 Canada vs U. S.

The average price spread between the two countries was 16.7 ¢/litre during the second quarter of 1992, down 2.2 ¢/litre from the first quarter. The average Canadian price went up 0.4 ¢/litre while the average American price increased 2.6 ¢/litre.

Crude costs decreased 0.8 ¢/litre in Canada during the second quarter of 1992, while they increased 0.4 ¢/litre on average in United States. The crude cost fluctuations, added to the higher seasonal demand for gasoline in the U. S., have resulted in a higher pump price increase in the United States than in Canada.

Higher taxes in Canada accounted for 91% of the price differential in the second quarter of 1992, an increase of 10% over the last quarter. Economies of scale generated by the larger market in United States have had less of an influence on price differentials recently.

Figure 9.3
Average Retail Price of Motor Gasoline
(Canada vs United States)

cents per litre

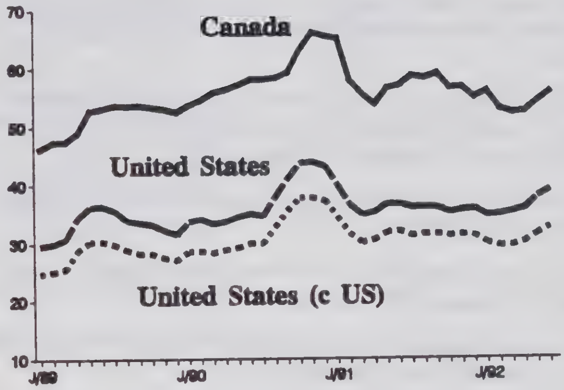
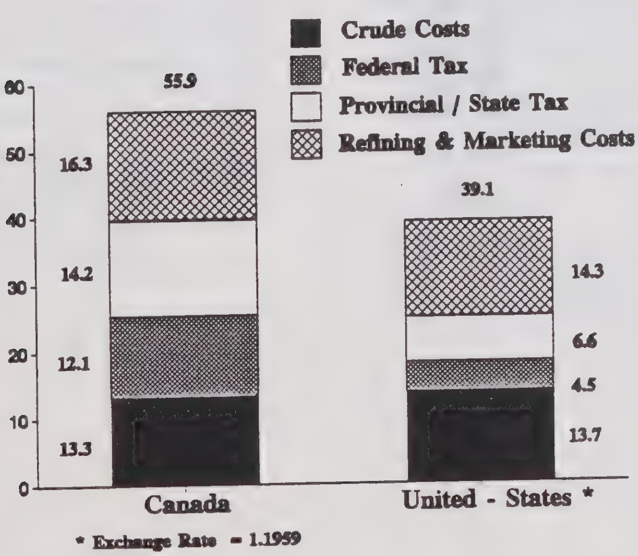


Figure 9.4
Breakdown of Average Pump Price
(June 1992)
cents per litre

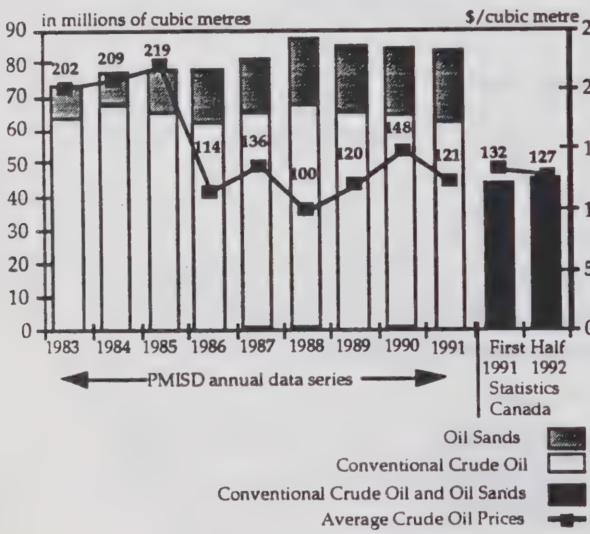


10. Financial Performance of the Canadian Oil and Gas Industry- First Half 1992

The following section was prepared by the Petroleum Monitoring and Information Services Division of the Economic and Financial Analysis Branch. Further information is available from V. Stanciulescu (613) 995-2100.

- Internal cash flow increased 11% to $3.1 billion in the first half of 1992 from $2.8 billion in the corresponding 1991 period.
- Net income after unusual items rose $135 million from a loss of $455 million in the first half of 1991 to a loss of $320 million in the same 1992 period.
- Gross capital expenditures decreased 24% to $3 billion in the first half of 1992.
- The reinvestment rate was 99% in the first half of 1992 vs. 144% in the same 1991 period.
- Dividend payments in the first half of 1992 decreased 26% to $495 million from $670 million.
- The petroleum industry's rate of return on capital employed for the first half of 1992 was zero vs. -0.2% for the same period in 1991.
- Long-term debt as a percentage of capital employed rose to 46% in the first half of 1992 from 45% at the end of 1991.

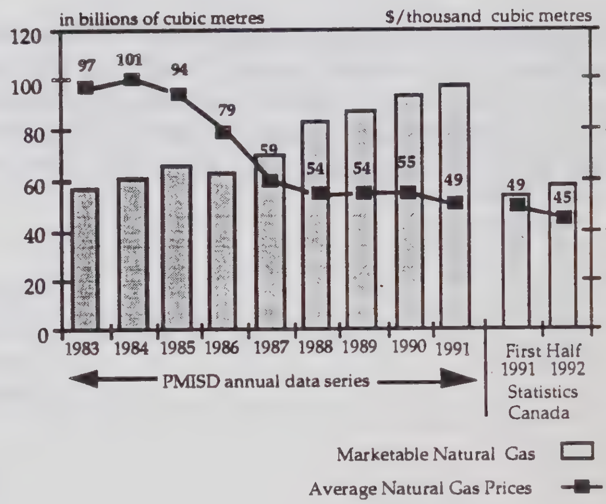
Chart 1 Crude Oil Volumes and Average Prices



Total sales revenues declined $1.4 billion (7%) to $19.5 billion in the first half of 1992 from $20.9 billion in the corresponding 1991 period. Upstream revenues declined as a result of lower crude oil and marketable natural gas prices, which more than offset increases in production volumes. In the downstream segment, lower refined product prices more than offset a slight increase in demand. At the beginning of 1991, the oil products industry was left with large inventories produced with high-cost crude oil. While companies were unable to recover the full cost of their inventories in the first half of 1991, prices in the earlier period were well above those in the first half of 1992.

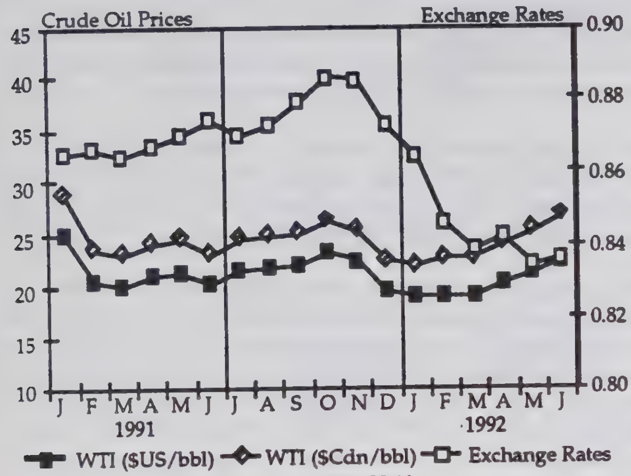
In addition to higher crude oil and marketable natural gas prices in the first half of 1991 vs. 1992, the sale of crude oil into the futures market resulted in higher revenues. This hedging operation was a significant source of revenue for a number of oil and gas producers. For the Canadian producers, the effect of lower international prices was partially offset by a weaker Canadian dollar in the first half of 1992 (Chart 3).

Chart 2 Marketable Natural Gas Volumes and Average Prices



Note A : Data for charts 1 and 2 were obtained from monitoring survey results except for the two end bars which are derived from Statistics Canada and EM & R. The monitoring survey covers approximately 90% of the industry, compared with 100% for the other data series.

Chart 3 Crude Oil Prices and Exchange Rates



	First Half 1991	1992
Avg. WTI ($US/bbl)	21.29	20.07
Avg. Exchange Rate	0.868	0.844
Avg. WTI Prices ($Cdn/bbl)	24.53	23.81

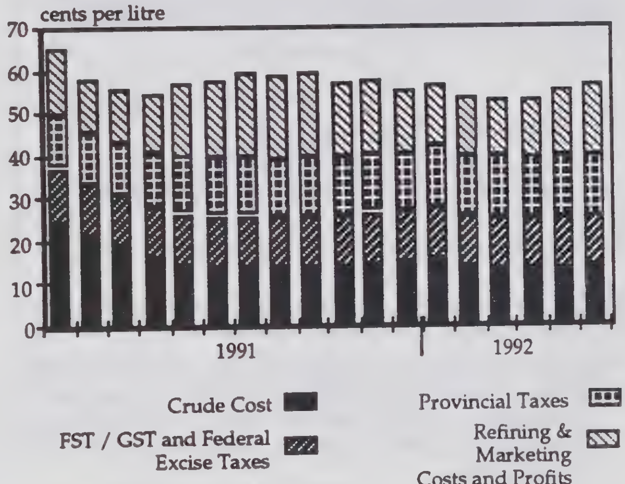
Sources: EMR, Oil and Gas Branch; Bank of Canada

Internal cash flow increased $315 million (11%), to $3.1 billion in the first half of 1992 from $2.8 billion in the corresponding 1991 period. The rise in cash flow was primarily due to lower 'Other expenses' of $2 billion (12%), which includes operating costs, cost of goods sold and royalty payments. Reduced 'Other expenses' more than offset the drop in revenues and a $155 million increase in current income taxes. The decline in 'Other expenses' was attributable to reduced operating costs, mostly as a result of cost management activities, and to change in accounting for cost of goods sold, a major expense in the Oil Products business. The 1992 results reflected the adoption by a number of integrated companies of the Last-In, First-Out (LIFO) method of inventory valuation, whereas the 1991 results were largely based on the First-In, First-Out (FIFO) method. The first half 1991 results reflect the results of high cost crude oil flowing into the system from production occurring at the end of 1990. Had this accounting change been applied retroactively, the difference in cost of goods sold between 1991 and 1992 would have been much smaller, reflecting only the actual change in crude oil prices.

Table 1 Overview of Total Industry

	First Half 1991	1992	Change	
	$ billions			(%)
Sales Revenues	20.9	19.5	-1.4	-7
Other Revenues	0.2	0.2	–	-9
Total Operating Expenses	21.3	19.3	-2.0	-9
Other Deductions	-0.1	-0.6	-0.5	–
All Current Taxes	0.3	0.5	0.2	47
Deferred Taxes	-0.1	-0.4	-0.3	–
Net Income before Extraordinary Items	**-0.5**	**-0.4**	**0.1**	**–**
Extraordinary and Other Items	–	0.1	0.1	–
Net Income after Extraordinary Items	**-0.5**	**-0.3**	**0.2**	**–**
Internal Cash Flow	**2.8**	**3.1**	**0.3**	**11**

Chart 4 Average Monthly Retail Price of Motor Gasoline

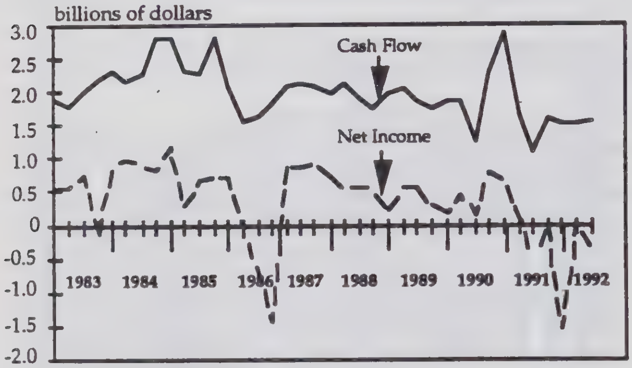


Source: EMR, Oil and Gas Branch

Net income from all Canadian operations of the industry rose $135 million from a loss of $455 million in the first half of 1991 to a loss of $320 million in the first half of 1992. Aside from the factors affecting cash flow, the increase was due to a reduction in E&D charged to current operations, down $115 million and deferred tax recoveries of $420 million in the first half of 1992 compared with recoveries of $140 million in the corresponding 1991 period.

Partly offsetting the rise in net income were higher write-offs of $390 million in the first half of 1992, lower gains on currency translation of $60 million, and higher depreciation, depletion and amortization charges of $155 million as a result of the inclusion of accrued costs for future site restoration in 1992 results. The level of assets write-offs in the first half of 1992 was particularly high as a major oil and gas producer accrued anticipated losses on the disposition and abandonment of oil and gas properties.

Chart 5 Net Income and Cash Flow Quarterly Data[(1)]



(1) While the 1992 results include the effects of changes in accounting methods, such as LIFO/FIFO inventory valuation and future removal and site restoration costs, prior years' data have not been restated even if several companies applied the changes retroactively.

Canadian-controlled companies' cash flow increased $220 million (18%) to $1.5 billion in the first half of 1992 from $1.2 billion in the corresponding 1991 period. The cash flow rise was due to lower 'Other expenses', which includes operating and feed stock costs, and royalties, down $440 million, that more than offset a slight decrease in revenues, $100 million or 1%, and an increase of $125 million in current income taxes.

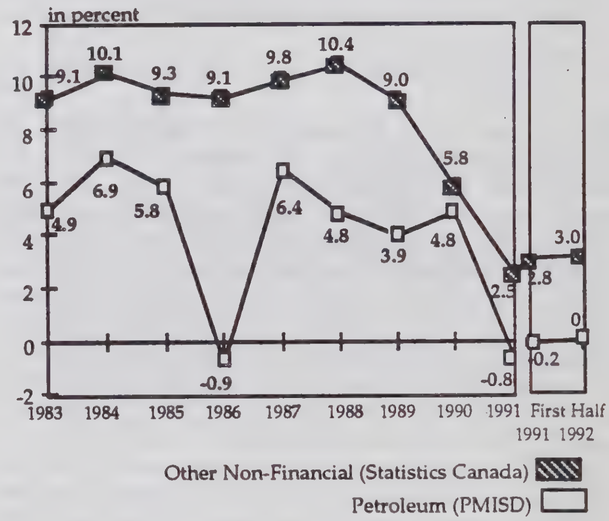
Net income rose $220 million from a loss of $120 million in the first half of 1991 to a profit of $100 million.

Foreign-controlled companies' cash flow increased $95 million, or 6%, to $1.6 billion in the first half of 1992 from $1.5 billion in the same 1991 period. Sales revenues declined to $12.6 billion (down $1.4 billion), while 'Other expenses', which includes operating and feed stock costs, and royalty payments, dropped $1.6 billion.

Net income declined $85 million to a loss of $420 million in the first half of 1992 from a loss of $335 million in the same 1991 period. The drop was primarily the result of increased assets write-offs, up $405 million.

The petroleum industry's annualized **rate of return on capital employed** at the end of the first half of 1992 was zero vs. -0.2% for the end of the comparable 1991 period. The other non-financial industries (excluding petroleum) recorded a rate of return on capital employed of 3.0% for the first half of 1992 vs. 2.8% in the same 1991 period (Chart 6 and Note B).

Chart 6 Rates of Return on Capital Employed



Dividend payments by the petroleum industry decreased 26% to $495 million in the first half of 1992 from $670 million in the corresponding 1991 period. Dividends paid by Canadian-controlled companies declined 25% to $175 million, while dividend payments by foreign-controlled companies dropped 27% to $320 million.

Table 2 Dividend Payments

	First Half 1991	First Half 1992	Percent of Net Income(1) First Half 1991	Percent of Net Income(1) First Half 1992
	$ millions		(%)	
Canadian-Controlled	233	176	–	178
Foreign-Controlled	438	318	–	–
Total Industry	672	494	–	–

(1) Percentages are derived by dividing dividend payments by net income; the netting of companies reporting losses against those reporting profits may yield unusual results in terms of payout rates.

Overall gross capital expenditures for the petroleum industry decreased 24% ($945 million) to $3 billion in the first half of 1992. Net of grants, incentives and contributions, capital expenditures declined 25% to $3 billion.

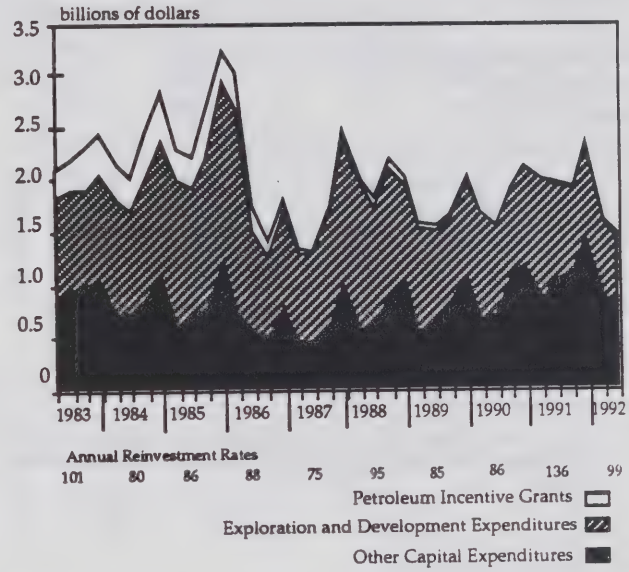
Table 3 Capital Expenditures and Reinvestment Rates

	First Half 1991	First Half 1992	Change	Change (%)
	—— $ billions ——			(%)
Gross Capital Expenditures	4.0	3.0	-1.0	-24
Less: Incentive, Grants and Contributions	*	0.1	0.1	–
Net Capital Expenditures	4.0	3.0	1.0	-25
Reinvestment Rate: Net Capital Expenditures as a Percent of Cash Flow	144%	99%		

* Less than $50 million.

Exploration and development spending declined 36% to $1.3 billion in the first half of 1992, while other capital expenditures on new construction, buildings, machinery and equipment, declined 9% to $1.7 billion. Gross capital outlays for Canadian-controlled companies declined 27% to $1.3 billion, while those of foreign-controlled companies decreased 21% to $1.7 billion (Table 5).

Chart 7 Capital Expenditures and Reinvestment Rates



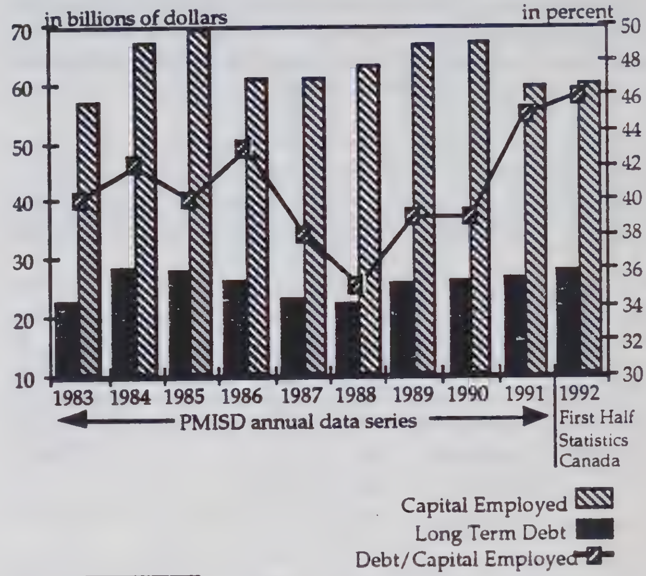
The total reinvestment rate was 99% in the first half of 1992 vs. 144% in the same period in 1991 (Table 4). The reinvestment rate for Integrateds and Refiners decreased to 91% from 159%, while the rate for the Oil and Gas Producers group fell to 105% from 136%.

Table 4 **Total Net Capital Expenditures(1) as a Percent of Internal Cash Flow**

	First Half 1991	First Half 1992
	(%)	
Integrateds and Refiners	159	91
Canadian-Controlled	280	57
Foreign-Controlled	142	104
Senior Oil and Gas Producers	134	105
Canadian-Controlled	126	107
Foreign-Controlled	147	101
Junior Oil and Gas Producers	145	103
Canadian-Controlled	151	96
Foreign-Controlled	137	113
Oil and Gas Producers	136	105
Canadian-Controlled	131	105
Foreign-Controlled	144	104
Total Industry	**144**	**99**
Canadian-Controlled	144	93
Foreign-Controlled	143	104

(1) Net capital expenditures are defined as gross capital expenditures less incentives, grants, tax credits and insurance receipts.

Chart 8 Debt(2) to Capital Employed



(2) Debt includes long-term debt and other long-term liabilities.

Debt to Equity Analysis

During the first half of 1992, the industry's total debt rose $1.1 billion to $27.8 billion from $26.7 billion at the end of 1991. The increase was largely attributable to the foreign-controlled group of companies which increased their debt by $1 billion to $16.8 billion. New debt was raised by this group of companies to redeem share capital and, to a lesser extent, to finance major capital projects. The increase was somewhat moderated by the transfer of a large portion of long-term debt due within the current year to current liabilities, pending refinancing. Canadian-controlled companies' debt increased $85 million.

Shareholders' equity declined $1.8 billion (5%) to $32.2 billion in the first half of 1992 compared to $34 billion at the end of 1991 (the drop in equity reflects the large ceiling test write-offs that occurred during the fourth quarter of 1991). Common and preferred share capital declined by $435 million (2%), while retained earnings decreased by $1.5 billion (12%). A number of companies replaced equity with long-term debt.

As a result of the above changes in debt and equity, the ratio of debt to capital employed (defined as long-term debt, other long-term liabilities and equity) increased to 46% in the first half of 1992 from 45% at the end of 1991 (Chart 8).

Second Quarter 1992

Net Income for the second quarter of 1992 rose $190 million from a loss of $560 million in 1991 to a loss of $370 million in 1992 (Table 8). The slight improvement was primarily due to higher sales revenues, up $205 million, or 2%, lower 'Other expenses', down $480 million, and deferred income tax recoveries of $235 million in the second quarter of 1992 compared with recoveries of $75 million in the corresponding 1991 period. Partly offsetting the rise in net income were higher write-offs of $370 million, and higher depreciation, depletion and amortization charges of $130 million. Internal cash flow, unaffected by write-offs, increased 42% to $1.5 billion from $1.1 billion.

Overall capital expenditures in the second quarter of 1992 decreased 26% to $1.4 billion. Exploration and development spending fell 36% to $600 million, while other capital expenditures declined 17% to $830 million (Table 6).

Note B: This report was prepared from quarterly data obtained from individual companies via Statistics Canada. In contrast to the semi-annual monitoring survey, the report covers the combined results of upstream, downstream and other Canadian operations but excludes the results of Canadian companies' foreign activities. In addition, this report contains about 50 fewer companies, mostly small or government owned. Nonetheless, the information contained in this analysis gives a reliable overview of the industry's financial performance for the first half of 1992.

Table 5

Capital Expenditures of Petroleum Industry
First Half

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1991	1992	Change	1991	1992	Change	1991	1992	Change
	$ millions		%	$ millions		%	$ millions		%
Exploration and Development (E&D)									
E&D Expensed (1)									
Land & Lease Acquisition and Retention	44	46	2	6	8	33	38	38	-2
Drilling Expenditures	239	156	-35	96	45	-53	143	111	-22
Geological and Geophysical	128	98	-23	11	13	18	116	85	-27
Total E&D Expensed	411	300	-27	113	66	-42	297	234	-21
E&D Capitalized									
Land & Lease Acquisition and Retention	333	174	-48	138	83	-40	195	90	-54
Drilling Expenditures	1163	781	-33	680	462	-32	483	319	-34
Geological and Geophysical	213	94	-56	131	50	-62	81	45	-44
Total E&D Capitalized	1709	1049	-39	949	595	-37	759	454	-40
Total Exploration and Development	**2120**	**1349**	**-36**	**1062**	**661**	**-43**	**1056**	**688**	**-35**
Other Capitalized Expenditures									
Mining	31	33	6	14	23	64	17	11	-35
New Const., Build., Mach., and Equip.	1651	1471	-11	686	609	-11	965	862	-11
Used Build., Mach., Equip., & Land	83	130	57	12	15	25	71	115	62
Other Capital Expenditures	104	64	-38	42	21	-50	62	42	-32
Total Other Capital Expenditures	1869	1698	-9	754	668	-11	1115	1030	-8
Total Capital Expenditures	**3989**	**3047**	**-24**	**1816**	**1329**	**-27**	**2171**	**1718**	**-21**
Capital Grants	33	68	106	17	24	41	16	43	169
Net Capital Expenditures	**3956**	**2979**	**-25**	**1799**	**1305**	**-27**	**2155**	**1675**	**-22**

(1) Excludes mining expenditures.

Table 6

Capital Expenditures of Petroleum Industry
Second Quarter

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1991	1992	Change	1991	1992	Change	1991	1992	Change
	$ millions		%	$ millions		%	$ millions		%
Exploration and Development (E&D)									
E&D Expensed (1)									
Land & Lease Acquisition and Retention	21	21	-3	2	2	27	19	18	-5
Drilling Expenditures	117	71	-39	40	22	-46	77	50	-35
Geological and Geophysical	45	40	-11	4	7	89	41	33	-20
Total E&D Expensed	183	132	-28	46	31	-33	137	101	-26
E&D Capitalized									
Land & Lease Acquisition and Retention	198	46	-77	65	30	-54	133	16	-88
Drilling Expenditures	455	383	-16	286	238	-17	168	145	-14
Geological and Geophysical	99	41	-59	54	19	-65	45	22	-51
Total E&D Capitalized	752	470	-38	405	287	-29	346	183	-47
Total Exploration and Development	**935**	**602**	**-36**	**451**	**318**	**-29**	**483**	**284**	**-41**
Other Capitalized Expenditures									
Mining	9	15	67	1	12	-	7	3	-57
New Const., Build., Mach., and Equip.	880	759	-14	306	272	-11	574	487	-15
Used Build., Mach., Equip., & Land	61	31	-49	4	6	40	57	25	-56
Other Capital Expenditures	56	27	-52	24	6	-75	33	21	-36
Total Other Capital Expenditures	1006	832	-17	335	296	-12	671	536	-20
Total Capital Expenditures	**1941**	**1434**	**-26**	**786**	**614**	**-22**	**1154**	**820**	**-29**
Capital Grants	16	40	-	8	12	41	8	28	-
Net Capital Expenditures	**1925**	**1394**	**-28**	**778**	**602**	**-23**	**1147**	**792**	**-31**

(1) Excludes mining expenditures.

Table 7

Income Statement
First Half

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	1991	1992	Change	1991	1992	Change	1991	1992	Change
	$ millions		%	$ millions		%	$ millions		%
Sales Revenues	**20933**	**19457**	**-7**	**6949**	**6847**	**-1**	**13984**	**12610**	**-10**
Other Revenues									
Interest from Canadian Sources	169	156	-7	76	85	13	93	71	-24
Dividends from Canadian Corporations	38	14	-64	20	12	-42	18	2	-88
Foreign Dividends and Interest Revenues	7	24	-	1	2	-	7	22	-
Total Revenues	**21147**	**19651**	**-7**	**7045**	**6944**	**-1**	**14101**	**12705**	**-10**
Expenses									
E & D Expensed	422	305	-28	114	66	-42	309	240	-22
D, D & A Charges	2810	2963	5	1159	1287	11	1651	1677	2
Other Expenses	17069	15060	-12	5313	4871	-8	11756	10189	-13
Interest Expenses	994	1009	2	472	471	-	522	539	3
Total Operating Expenses	**21296**	**19338**	**-9**	**7057**	**6694**	**-5**	**14238**	**12644**	**-11**
Other Transactions									
Gains on Translation of Currency	31	-26	-	-18	-8	59	49	-18	-
Gains on Sale of Assets	157	135	-14	119	52	-57	38	84	121
Write-offs and Valuation Adjustments	-332	-724	-	-104	-93	-	-228	-631	-
Income before Income Taxes	**-294**	**-327**	**-**	**-16**	**203**	**-**	**-278**	**-531**	**-**
Income Taxes									
Current	331	487	47	16	141	-	316	347	10
Deferred (tax allocation method)	-139	-422	-	125	18	-86	-264	-439	-
Net Income after income taxes	**-486**	**-393**	**-**	**-157**	**45**	**-**	**-330**	**-438**	**-**
Other Income									
Equity Income	29	72	148	36	51	42	-4	21	-
Extraordinary Items	-	-		-	-	-	-	-	-
Net income after Extraordinary Items	**-455**	**-319**	**-**	**-121**	**99**	**-**	**-334**	**-417**	**-**
Cash Flow	**2752**	**3068**	**11**	**1245**	**1464**	**18**	**1508**	**1604**	**6**

	Integrateds and Refiners			Oil and Gas Producers		
	1991	1992	Change	1991	1992	Change
	$ millions		%	$ millions		%
Sales Revenues	**13301**	**12185**	**-8**	**7633**	**7272**	**-5**
Other Revenues						
Interest from Canadian Sources	62	58	-7	106	98	-7
Dividends from Canadian Corporations	9	2	-82	29	12	-58
Foreign Dividends and Interest Revenues	-	2		7	22	-
Total Revenues	**13372**	**12245**	**-8**	**7775**	**7405**	**-5**
Expenses						
E & D Expensed	146	79	-46	277	227	-18
D, D & A Charges	1085	1139	5	1725	1824	6
Other Expenses	12090	10322	-15	4979	4739	-5
Interest Expenses	442	366	-17	553	644	17
Total Operating Expenses	**13763**	**11905**	**-14**	**7533**	**7434**	**-1**
Other Transactions						
Gains on Translation of Currency	11	-1	-	20	-25	-
Gains on Sale of Assets	63	118	89	94	17	-82
Write-offs and Valuation Adjustments	-166	-139	-	-167	-585	-
Income before Income Taxes	**-483**	**320**	**-**	**189**	**-648**	**-**
Income Taxes			-			
Current	-45	262	-	377	225	-40
Deferred (tax allocation method)	-54	-72	-	-85	-349	-
Net Income after income taxes	**-384**	**130**	**-**	**-102**	**-523**	**-**
Other Income						
Equity Income	16	18	13	14	55	-
Extraordinary Items	-	-	-	-	-	-
Net income after Extraordinary Items	**-368**	**148**	**-**	**-87**	**-466**	**-**
Cash Flow	**886**	**1297**	**46**	**1867**	**1771**	**-5**

Table 8

Income Statement
Second Quarter

	Total Industry 1991	Total Industry 1992	Total Industry Change	Canadian-Controlled 1991	Canadian-Controlled 1992	Canadian-Controlled Change	Foreign-Controlled 1991	Foreign-Controlled 1992	Foreign-Controlled Change
	$ millions		%	$ millions		%	$ millions		%
Sales Revenues	**9905**	**10109**	**2**	**3239**	**3565**	**10**	**6666**	**6545**	**-2**
Other Revenues									-
Interest from Canadian Sources	82	74	-9	38	39	2	44	36	-18
Dividends from Canadian Corporations	12	4	-65	7	3	-56	5	1	-80
Foreign Dividends and Interest Revenues	3	22	-	1	1	80	2	21	-
Total Revenues	**10001**	**10209**	**2**	**3284**	**3606**	**10**	**6717**	**6602**	**-2**
Expenses									
E & D Expensed	188	135	-28	45	31	-33	143	105	-27
D, D & A Charges	1357	1489	10	576	629	9	781	860	10
Other Expenses	8408	7930	-6	2529	2530	-	5878	5400	-8
Interest Expenses	491	503	2	237	233	-2	254	270	6
Total Operating Expenses	**10445**	**10057**	**-4**	**3388**	**3423**	**1**	**7056**	**6634**	**-6**
Other Transactions									
Gains on Translation of Currency	31	-23	-	-	-7	-	30	-16	-
Gains on Sale of Assets	96	42	-56	114	9	-92	-18	33	-
Write-offs and Valuation Adjustments	-304	-675	-	-102	-92	-	-203	-583	-
Income before Income Taxes	**-622**	**-529**	**15**	**-92**	**94**	-	**-530**	**-623**	-
Income Taxes									
Current	19	208	-	-5	39	-	24	169	-
Deferred (tax allocation method)	-75	-312	-	66	23	-65	-141	-335	-
Net Income after income taxes	**-565**	**-426**	-	**-153**	**32**	-	**-412**	**-458**	-
Other Income									
Equity Income	4	57	-	1	34	-	2	2	-
Extraordinary Items	-	3	-	-	3	-	-	-	-
Net income after Extraordinary Items	**-559**	**-367**	-	**-152**	**68**	-	**-408**	**-435**	-
Cash Flow	**1083**	**1542**	**42**	**523**	**805**	**54**	**561**	**737**	**31**

	Integrateds and Refiners 1991	Integrateds and Refiners 1992	Integrateds and Refiners Change	Oil and Gas Producers 1991	Oil and Gas Producers 1992	Oil and Gas Producers Change
	$ millions		%	$ millions		%
Sales Revenues	**6360**	**6407**	**1**	**4910**	**3816**	**-22**
Other Revenues						
Interest from Canadian Sources	23	35	52	59	40	-33
Dividends from Canadian Corporations	3	1	-67	8	3	-61
Foreign Dividends and Interest Revenues	0	1	-	3	21	-
Total Revenues	**6386**	**6443**	**1**	**4980**	**3880**	**-22**
Expenses						
E & D Expensed	67	30	-55	121	106	-13
D, D & A Charges	515	570	11	843	919	9
Other Expenses	5980	5512	-8	2428	2418	0
Interest Expenses	210	187	-11	282	316	12
Total Operating Expenses	**6771**	**6299**	**-7**	**3674**	**3759**	**2**
Other Transactions						
Gains on Translation of Currency	5	-4	-	25	-19	-
Gains on Sale of Assets	1	45	-	95	-4	-
Write-offs and Valuation Adjustments	-170	-104	-	-134	-570	-
Income before Income Taxes	**-549**	**82**	-	**-73**	**-612**	-
Income Taxes						
Current	-55	125	-	73	84	14
Deferred (tax allocation method)	-96	-85	-	20	-226	-
Net Income after income taxes	**-399**	**43**	-	**-166**	**-469**	-
Other Income						
Equity Income	-	2	-	4	55	-
Extraordinary Items	-	-	-	-	-31	-
Net income after Extraordinary Items	**-399**	**45**	-	**-160**	**-412**	-
Cash Flow	**251**	**620**	**147**	**832**	**922**	**11**

Table 9

Balance Sheet

	Total Industry			Canadian-Controlled			Foreign-Controlled		
	Dec. 31 1991	Jun. 30 1992	Change	Dec. 31 1991	Jun. 30 1992	Change	Dec. 31 1991	Jun. 30 1992	Change
		$ millions	%		$ millions	%		$ millions	%
Cash, Investments and Marketable Securities	426	592	39	206	225	9	220	367	67
Accounts Receivable:	0	0							
Trade (include affiliates)	5328	5042	-5	1903	1774	-7	3424	3268	-5
All Other	696	848	22	335	275	-18	361	573	59
Total	6024	5889	-2	2239	2049	-8	3785	3840	1
Inventories	3411	3242	-5	1136	1143	1	2275	2098	-8
Other Current Assets	2319	2567	11	1103	887	-20	1216	1680	38
Total Current Assets	**12179**	**12290**	**1**	**4683**	**4304**	**-8**	**7496**	**7986**	**7**
Net Fixed and Depletable Assets	60847	58958	-3	25715	25139	-2	35132	33819	-4
Other Long-term Assets	7575	7956	5	4124	4327	5	3451	3629	5
Total Assets	**80602**	**79204**	**-2**	**34522**	**33770**	**-2**	**46080**	**45434**	**-1**
Accounts payable:	0	0							
Trade (include affiliates)	4401	3893	-12	1784	1616	-9	2616	2277	-13
All Other	2095	1995	-5	588	647	10	1507	1349	-10
Total	6496	5888	-9	2373	2263	-5	4123	3625	-12
Other Current Liabilities	3249	4002	23	1276	1229	-4	1973	2773	41
Total Current Liabilities	**9745**	**9890**	**1**	**3649**	**3492**	**-4**	**6096**	**6398**	**5**
Long-term Debt	23503	24298	3	9668	9447	-2	13835	14851	7
Accumulated Deferred Income Taxes	10081	9292	-8	4120	3876	-6	5961	5416	-9
Other Long-term Liabilities	3233	3525	9	1296	1601	24	1937	1924	-1
Shareholders' Equity	0	0							
Common	14611	14578	-	8548	8721	2	6063	5856	-3
Preferred	3186	2781	-13	1568	1490	-5	1619	1291	-20
Retained earnings	11821	10355	-12	2796	2262	-19	9026	8093	-10
Contributed surplus	4422	4484	1	2879	2880	-	1543	1604	4
Total Liab., def. Taxes and Equity	**80602**	**79204**	**-2**	**34522**	**33770**	**-2**	**46080**	**45434**	**-1**
Working Capital	**2435**	**2400**	**-1**	**1035**	**812**	**-22**	**1400**	**1588**	**13**

	Integrateds and Refiners			Oil and Gas Producers		
	Dec. 31 1991	Jun. 30 1992	Change	Dec. 31 1991	Jun. 30 1992	Change
		$ millions	%		$ millions	%
Cash, Investments and Marketable Securities	62	80	29	364	512	41
Accounts Receivable:						
Trade (include affiliates)	3157	3114	-1	2171	1928	-11
All Other	402	546	36	294	302	3
Total	3559	3660	3	2465	2230	-10
Inventories	2878	2659	-8	533	583	9
Other Current Assets	667	1322	98	1652	1245	-25
Total Current Assets	**7166**	**7721**	**8**	**5014**	**4570**	**-9**
Net Fixed and Depletable Assets	26798	26333	-2	34049	32625	-4
Other Long-term Assets	2212	2128	-4	5363	5828	9
Total Assets	**36176**	**36182**	**-**	**44426**	**43022**	**-3**
Accounts payable:						
Trade (include affiliates)	2594	2428	-6	1806	1465	-19
All Other	1115	1076	-3	980	919	-6
Total	3709	3504	-6	2787	2384	-14
Other Current Liabilities	1587	1641	3	1661	2361	42
Total Current Liabilities	**5296**	**5145**	**-3**	**4448**	**4745**	**7**
Long-term Debt	8591	9628	12	14912	14670	-2
Accumulated Deferred Income Taxes	4592	4443	-3	5489	4849	-12
Other Long-term Liabilities	1368	1601	17	1866	1924	3
Shareholders' Equity						
Common	5585	5291	-5	9026	9287	3
Preferred	366	5	-99	2820	2777	-2
Retained earnings	7469	7160	-4	4352	3195	-27
Contributed surplus	2909	2909	-	1513	1575	4
Total Liab., def. Taxes and Equity	**36176**	**36182**	**-**	**44426**	**43022**	**-3**
Working Capital	**1870**	**2575**	**38**	**567**	**-175**	**-**

Appendix I
Production of Crude Oil and Equivalent
(000 m^3/d)

	1991 1Q	1991 2Q	1991 3Q	1991 4Q	1991 Year	1992 1Q	1992 2Q
A. Light and Equivalent							
Conventional							
Alberta	116.0	110.1	110.2	112.5	112.2	114.6	108.7
B.C.	5.6	5.3	5.5	5.7	5.5	5.5	5.4
Saskatchewan	11.6	11.0	10.5	11.4	11.1	11.4	11.2
Manitoba	2.0	1.9	1.9	1.9	1.9	1.8	1.9
Ontario	0.6	0.7	0.6	0.6	0.6	0.6	0.7
Other	5.2	5.2	5.2	5.2	5.2	5.3	5.9
Total	**141.0**	**134.2**	**133.9**	**137.3**	**136.5**	**138.8**	**133.8**
Synthetic							
Suncor	9.9	10.0	9.4	9.1	9.6	10.2	6.4
Syncrude	25.2	22.8	27.4	29.6	26.3	27.6	26.4
Total	**35.1**	**32.8**	**36.8**	**38.7**	**35.9**	**37.8**	**32.8**
Pentanes Plus (excluding diluent)	**6.4**	**6.6**	**5.6**	**9.0**	**8.6**	**8.9**	**5.7**
Total Light	**182.5**	**173.6**	**176.3**	**185.0**	**179.3**	**185.5**	**172.3**
B. Heavy Crude							
Alberta							
Conventional	30.1	30.0	30.0	32.1	30.6	33.9	32.5
Bitumen	21.2	18.8	21.5	16.5	19.5	18.4	21.8
Diluent	10.2	8.3	9.8	8.6	9.3	9.6	10.3
Total	**61.5**	**57.1**	**61.3**	**57.2**	**59.4**	**61.9**	**64.6**
Saskatchewan							
Conventional	22.3	21.1	22.2	23.4	22.3	23.4	23.1
Diluent	3.4	2.8	2.9	3.3	3.1	3.4	3.2
Total	**25.7**	**23.9**	**25.1**	**26.7**	**25.4**	**26.8**	**26.3**
Total Heavy	**87.2**	**81.0**	**86.4**	**83.9**	**84.8**	**88.7**	**90.9**
C. Production	**269.7**	**254.6**	**262.7**	**268.9**	**264.1**	**274.2**	**263.2**

Appendix II
Supply and Disposition of Crude Oil and Equivalent
(000 m³/d)

	1991 1Q	1991 2Q	1991 3Q	1991 4Q	1991 Year	1992 1Q	1992 2Q
A. Light and Equivalent							
Supply							
Production	182.7	173.5	176.3	185.0	179.4	185.6	172.3
Newgrade	2.4	0.3	2.2	3.3	2.0	3.4	0.7
Draw/(Build) *	5.3	9.8	8.9	8.1	8.1	13.7	13.1
Net Supply	190.4	183.6	187.4	196.4	189.5	202.7	186.1
Domestic Demand							
Atlantic	0	0	0	0	0	0	0
Quebec	4.9	3.2	2.6	0	2.7	0	0
Ontario	56.6	56.2	59.6	63.0	58.8	61.3	51.0
Prairies	45.1	46.0	47.9	47.8	46.6	43.2	40.5
B.C.	18.1	16.5	20.3	20.4	18.9	20.0	21.2
Total	**124.7**	**121.9**	**130.3**	**131.1**	**127.0**	**124.4**	**112.7**
Exports	**65.6**	**61.8**	**57.0**	**65.2**	**62.4**	**78.3**	**73.4**
Total Demand	**190.3**	**183.7**	**187.3**	**196.3**	**189.4**	**202.7**	**186.1**
B. Heavy Crude (Blended)							
Supply							
Production	87.2	81.1	86.4	83.9	84.7	88.7	90.9
Recycled Diluent	0.7	1.3	1.5	0.5	1.0	0.8	1.1
Draw/(Build) *	(3.1)	(4.7)	(6.2)	(5.9)	(5.0)	(11.8)	(16.1)
Net Supply	84.8	77.7	81.7	78.5	80.7	77.7	75.9
Domestic Demand							
Atlantic	0	0	0	0	0	0	0
Quebec	0	0	0	0.1	0.1	0	0
Ontario	9.1	11.4	10.9	9.3	10.2	7.7	11.2
Prairies	9.1	6.7	14.4	10.7	10.3	11.4	8.9
B.C.	0.5	0.5	0.7	0.7	0.6	0.6	0.5
Total	**18.8**	**18.7**	**25.9**	**20.8**	**21.1**	**19.6**	**20.6**
Exports	**66.1**	**58.9**	**55.7**	**57.8**	**59.6**	**58.1**	**55.3**
Total Demand	**84.9**	**77.6**	**81.6**	**78.6**	**80.7**	**77.7**	**75.9**

* *includes statistical error*

Appendix III
Crude Oil Exports by Destination
(000 m^3/d)

		1991 1Q	1991 2Q	1991 3Q	1991 4Q	1991 Year	1992 1Q	1992 2Q
U.S. PAD Districts *								
I	Light	6.5	6.8	8.9	6.8	7.2	7.4	8.3
	Heavy	1.7	1.0	1.0	1.5	1.3	1.3	1.4
	Total	**8.2**	**7.8**	**9.9**	**8.3**	**8.5**	**8.7**	**9.7**
II	Light	47.2	42.2	34.1	44.5	41.9	53.6	51.6
	Heavy	55.5	54.3	48.3	49.2	51.8	53.5	48.6
	Total	**102.7**	**96.5**	**82.4**	**93.7**	**93.7**	**107.1**	**100.2**
III	Light	0	0	0	0	0	0	0
	Heavy	3.1	0	0.6	2.5	1.5	0	0
	Total	**3.1**	**0**	**0.6**	**2.5**	**1.5**	**0**	**0.8**
IV	Light	9.4	10.5	12.2	12.3	11.0	13.0	8.7
	Heavy	2.9	2.2	3.7	3.4	3.0	2.5	4.9
	Total	**12.3**	**12.7**	**15.9**	**15.7**	**14.0**	**15.5**	**13.6**
V	Light	1.3	1.3	1.8	0.9	1.3	2.5	2.9
	Heavy	0.4	0.7	0.4	0.4	0.5	0	0.5
	Total	**1.7**	**2.0**	**2.2**	**1.3**	**1.8**	**2.5**	**3.4**
Total U.S.	**Light**	**64.4**	**60.8**	**57.0**	**64.5**	**61.5**	**76.5**	**72.3**
	Heavy	**63.6**	**58.2**	**54.0**	**57.0**	**58.0**	**57.3**	**55.4**
	Total	**128.0**	**119.0**	**111.0**	**121.5**	**119.5**	**133.8**	**127.7**
Offshore	Light	0.8	0.8	0	0.9	0.6	1.5	1.1
	Heavy	2.3	0.8	1.7	0.9	1.4	0.9	0
	Total	**3.1**	**1.6**	**1.7**	**1.8**	**2.0**	**2.4**	**1.1**
Total	**Light**	**65.2**	**61.6**	**57.0**	**65.4**	**62.1**	**78.0**	**73.4**
	Heavy	**65.9**	**59.0**	**55.7**	**57.9**	**59.4**	**58.2**	**55.4**
	Total	**131.1**	**120.6**	**112.7**	**123.3**	**121.6**	**136.2**	**128.8**

* *U.S. Petroleum Administration for Defense (PAD) Districts*

Appendix IV
Pipeline Deliveries
(000 m³/d)

	1991 1Q	1991 2Q	1991 3Q	1991 4Q	1991 Year	1992 1Q	1992 2Q
A. Trans Mountain Pipe Line (TMPL)							
Domestic Deliveries							
Light Crude	14.5	14.1	18.7	19.7	16.8	19.0	21.1
Heavy Crude	0.4	0.2	1.1	0.3	0.5	0	0.2
Semi Refined Poducts	5.5	3.7	3.2	3.2	3.9	3.1	1.7
Refined Products	2.4	2.0	2.7	2.9	2.5	2.7	2.4
Total	22.8	20.0	25.7	26.1	23.7	24.8	25.4
Foreign Deliveries							
Tankers	5.7	2.2	3.5	4.5	4.0	4.0	4.6
Puget Sound Area	1.1	1.6	1.0	0.8	1.1	1.7	2.2
Total	6.8	3.8	4.5	5.3	5.1	5.7	6.8
Total TMPL	**29.6**	**23.8**	**30.2**	**31.4**	**28.8**	**30.4**	**32.2**
B. Interprovincial Pipe Line (IPL)							
Domestic Deliveries							
Light Crude	74.2	74.8	73.1	74.3	74.1	74.0	63.3
Heavy Crude	12.3	12.3	16.0	14.5	13.8	13.6	15.4
Other (1)	28.6	26.5	25.4	28.1	27.2	31.3	28.6
Total	115.1	113.6	114.5	116.9	115.1	118.9	107.3
Foreign Deliveries							
Light Crude	54.2	49.6	42.6	51.4	49.5	59.5	58.0
Heavy Crude	57.6	55.3	49.5	50.6	53.2	54.8	50.1
Other (1)(2)	6.8	7.8	5.6	7.0	6.7	6.6	5.5
Total	118.6	112.7	97.7	109.0	109.4	120.9	113.6
Total IPL	**233.7**	**226.1**	**212.2**	**225.9**	**224.5**	**239.8**	**220.9**
C. Pipelines to Montreal							
IPL Deliveries							
To Montreal	4.9	4.2	1.0	0	2.4	0	0
For Export/Transfer	0	0	0	0	0	0	0
Total IPL	4.9	4.2	1.0	0	2.4	0	0
Portland-Montreal							
Montreal Imports (3)	24.2	22.4	24.4	29.1	25.0	28.4	20.8
Total Montreal Receipts	**29.1**	**26.6**	**25.4**	**29.1**	**27.4**	**28.4**	**20.8**

(1) includes petroleum products and NGL's.
(2) includes US domestic crudes delivered to the U.S.
(3) includes cargos imported directly into Montreal

Appendix V
Canadian Refinery Receipts
(000 m^3/d)

		1991					1992	
		1Q	2Q	3Q	4Q	Year	1Q	2Q
A.	**Domestic Receipts**							
	Light & Equivalent							
	Atlantic	0	0	0	0	0	0	0
	Quebec	4.9	3.1	2.6	0	0	0	0
	Ontario	56.6	56.2	59.6	63.0	58.9	61.3	51.0
	Prairies	45.1	46.0	47.9	47.7	46.7	43.2	40.5
	B.C.	18.1	16.5	20.3	20.4	18.8	19.9	21.2
	Total	**124.7**	**121.8**	**130.4**	**131.1**	**124.4**	**124.4**	**112.7**
	Heavy							
	Atlantic	0	0	0	0	0	0	0
	Quebec	0	0	0	0.1	0	0	0
	Ontario	9.1	11.4	10.9	9.3	10.2	7.7	11.2
	Prairies	9.0	6.7	14.4	10.6	10.2	11.4	8.9
	B.C.	0.6	0.5	0.7	0.7	0.6	0.6	0.5
	Total	**18.7**	**18.6**	**26.0**	**20.7**	**21.0**	**19.7**	**20.6**
	Other (including partially processed)							
	Atlantic	0	1.2	0.2	0	0.3	0	0
	Quebec	0	0.2	0	0	0.1	0	0
	Ontario	3.4	5.3	4.6	4.8	4.5	4.9	4.0
	Prairies	3.6	6.1	3.6	2.3	3.9	3.8	1.5
	B.C.	5.5	4.0	3.5	3.5	4.1	3.3	2.0
	Total	**12.5**	**16.8**	**11.9**	**10.6**	**12.9**	**12.0**	**7.5**
	Total Domestic Receipts							
	Atlantic	0	1.2	0.2	0	0.3	0	0
	Quebec	4.9	3.3	2.6	0.1	0.1	0	0
	Ontario	69.1	72.9	75.1	77.1	73.6	73.9	66.2
	Prairies	57.7	58.8	65.9	60.6	60.8	58.4	50.9
	B.C.	24.2	21.0	24.5	24.6	23.5	23.8	23.7
	Total	**155.9**	**157.2**	**168.3**	**162.4**	**158.3**	**156.1**	**140.8**
B.	**Crude Oil Imports**							
	Atlantic	50.7	37.6	56.3	54.2	49.7	45.2	42.3
	Quebec	39.6	35.7	44.2	47.8	41.9	43.5	39.7
	Ontario	0.6	0.4	0.5	0.1	0.4	0.2	0.9
	Prairies	0	0	0	0	0	0	0
	B.C.	0	0	0	0	0	0	0.1
	Total	**90.9**	**73.7**	**101.0**	**102.1**	**92.0**	**88 .9**	**83.0**
C.	**Total Receipts**							
	Atlantic	50.7	38.8	56.5	54.2	50.0	45.2	42.3
	Quebec	44.5	39.0	46.8	47.9	42.0	43.5	39.7
	Ontario	69.7	73.3	75.6	77.2	74.0	74.1	67.1
	Prairies	57.7	58.8	65.9	60.6	60.8	58.4	50.9
	B.C.	24.2	21.0	24.5	24.6	23.5	23.8	23.8
	Total	**246.8**	**230.9**	**269.3**	**264.5**	**250.3**	**245.1**	**223.8**

Appendix VI
International and Domestic Crude Oil Prices
(US$/bbl)

A.	AT SOURCE		Canadian Par	WTI NYMEX	Brent
	1990	Ave.	23.73	24.49	23.87
	1991	1Q	20.72	21.81	20.95
		2Q	19.73	20.77	18.94
		3Q	20.52	21.65	19.90
		4Q	20.63	21.77	20.59
		Ave.	20.40	21.50	20.09
	1992	1Q	17.87	18.92	17.96
		2Q	20.06	21.23	19.98

B.	AT CHICAGO		Canadian Par	WTI NYMEX	Brent
	1990	Ave.	25.00	25.09	25.70
	1991	1Q	22.01	22.41	23.22
		2Q	21.01	21.37	20.93
		3Q	21.81	22.25	21.90
		4Q	21.92	22.36	22.42
		Ave.	21.69	22.09	22.11
	1992	1Q	18.98	19.52	19.59
		2Q	21.40	21.82	21.58

C.	AT MONTREAL		Canadian Par	Brent
	1990	Ave.	25.21	25.61
	1991	1Q	22.29	22.88
		2Q	21.30	20.59
		3Q	(1)	21.47
		4Q	-	22.07
		Ave.	-	21.74
	1992	1Q	-	19.38
		2Q	-	21.30

(1) the last delivery of domestic crude to Montreal via the Sarnia - Montreal pipeline was reported in July of 1991

Appendix VII
Average Regular Unleaded Gasoline Prices
(Self-Serve)
1991-1992

	1991			1992	
	June 25	Sept. 24	Dec. 31	Mar. 31	June 30
	cents per litre				
St John's (NFLD)	61.8	61.8	61.8	60.9	60.9
Charlottetown	60.3	60.6	61.1	60.3	60.0
Halifax *	60.3	60.2	59.9	59.0	58.9
Saint John (N.B.) *	57.7	60.0	60.0	56.8	54.5
Montreal	63.2	66.5	63.8	59.0	61.8
Toronto	57.5	57.9	47.7	49.6	58.1
Winnipeg	47.2	53.8	49.8	46.8	53.9
Regina	38.9	42.9	50.9	41.9	43.9
Calgary	47.6	50.5	49.2	42.5	51.6
Vancouver	53.2	49.9	49.6	55.9	56.9
Average	**56.1**	**57.7**	**53.7**	**52.4**	**57.4**
Consumption taxes include:					
Federal	12.1	12.2	11.9	11.8	12.2
Provincial	12.9	13.1	13.1	13.8	14.0

* *Full-Serve*

Appendix VIII
Consumption Taxes on Petroleum Products
(June 1992)

	Ad valorem		Gasoline			Diesel
	Mogas	Diesel	Reg UL	Mid UL	Prem UL	
	----------%----------		------------------ (cents per litre) --------------			
Federal Taxes						
Estimated GST (7%)			3.7	3.9	4.2	3.3
Excise			8.5	8.5	8.5	4.0
Provincial Taxes						
Newfoundland [a]			13.7	13.7	13.7	15.6
Prince Edward Island	23	26	11.6	11.6	11.6	11.6
Nova Scotia	24.5	31.5	12.5	12.5	12.5	14.1
New Brunswick			10.7	10.7	10.7	13.7
Quebec [b]			19.1	19.3	19.6	18.7
Ontario			14.7	14.7	14.7	14.3
Manitoba			10.5	10.5	10.5	10.9
Saskatchewan			13.0	13.0	13.0	13.0
Alberta			9.0	9.0	9.0	9.0
British Columbia [c]			10.0	10.0	10.0	10.5
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	(d)	9.4	9.4	9.4	8.0

(a) The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay, Labrador.

(b) Reduced by varying amounts in certain remote areas and within 20 kilometres of the provincial and U.S. borders.

(c) Additional transit tax of 3.0 cents per litre in Vancouver.

(d) 85% of gasoline tax.

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional area	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude Oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydro carbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Synthetic crude oil	Crude oil production treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

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The Canadian Oil Market

Vol VIII, No. 3, Fall 1992

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The Canadian Oil Market

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Canadian Oil Markets and Emergency Planning Division
Energy Sector
Energy, Mines and Resources Canada

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Table of Contents

The Canadian Oil Market

Overview

This issue of the Canadian Oil Market reviews Canadian oil supply and demand developments with emphasis on the third quarter of 1992. Also included is an abridged version of a report entitled **'A Review of Gasoline Retailing, Canada vs United States (Update 1980-1990)'.**

Highlights

- After showing some signs of recovery in the first half of 1992, demand for refined petroleum products faltered in the third quarter. The rise and subsequent fall in product consumption largely reflected the trend in heavy fuel oil sales.

- Canada produced significantly more crude oil in the third quarter of 1992 than a year earlier. The downward trend in conventional light crude oil production was reversed reflecting steady production in western Canada and the start up in June of the Cohasset/Panuke development off the coast of Nova Scotia.

- Refineries reacted to the slump in domestic refined product markets by reducing crude runs. Refinery throughput continued to fall in the third quarter with capacity utilization down 3 percentage points to 83%.

- Crude oil imports fell in the third quarter on account of a sizeable drop in crude oil receipts by refineries in the Atlantic region. This reflected both a slump in the region's refined product markets and a lengthy turnaround at the Come-by-Chance refinery in Newfoundland.

- Crude oil exports continued to grow in the third quarter, mostly because of depressed crude oil markets in Ontario and western Canada. All the incremental exports were delivered to refineries in the U.S. Midwest.

The Canadian Oil Market will no longer publish Canadian oil and gas industry financial information prepared by the *Petroleum Monitoring and Information Services Division* on a quarterly basis. The information will be published twice yearly with the 1992 year-end financial position available in the next issue of the Canadian Oil Market. Quarterly information is available from V. Stanciulescu at (613) 995-2100.

The Canadian Oil Market

1. Refined Petroleum Product Consumption

. Demand for refined petroleum products in Canada remained weak despite a modest increase in domestic crude oil production.

Total refined petroleum product demand during the third quarter of 1992 fell to slightly below 225 000 m^3/d. This represented a decline of 1% from a year earlier and 7% from two years ago. Refined product markets have been sluggish since the onset of the recession.

Sales of motor gasoline averaged 98 000 m^3/d, unchanged from last year. Demand for diesel fuel declined by 3% to 47 000 m^3/d. Unseasonably cold weather in central Canada led to a 4% increase, to almost 9 000 m^3/d, in heating oil consumption. Heavy fuel oil continues to account for a disproportionate share of the variability in total product demand.

Heavy fuel oil sales fell by almost 10% to 20 000 m^3/d, reflecting falling demand in the Atlantic region and British Columbia, offset partially by higher sales in Ontario. To help make up for a shortfall in nuclear power generation, Ontario has stepped up its use of heavy fuel oil to generate electricity in the last year. Demand for other products rose marginally to 53 000 m^3/d, largely on the strength of increased petrochemical feedstock sales.

Not surprisingly, the slump in refined petroleum product demand has curtailed crude oil demand, and crude runs, at Canadian refineries. In the third quarter, crude oil demand fell by 13 000 m^3/d to 244 000 m^3/d. Concurrently, refinery utilization fell 3 percentage points to 83%. The drop in the utilization rate would have been larger still had not some excess refining capacity in the Prairies been removed in May with the permanent closure of Calgary's Turbo refinery.

Figure 1.1
Refined Petroleum Product Sales
000 m^3/d

2. Drilling and Exploration Activity

. The drilling industry in western Canada appears to be poised for a modest rebound on the heels of sweeping royalty changes in Alberta.

The level of drilling activity in western Canada continued to fall short of industry expectations. Alberta's attempt to stir drilling activity by its temporary royalty holiday program, introduced late in 1991, had little affect on the industry.

An average of 108 of 427 drilling rigs were reported active during the first nine months of 1992 for an active rig utilization rate of about 25%. This compares with 159 of 461 active rigs a year earlier. During the third quarter of the year, 111 of 419 rigs were reported active compare to 123 of 461 a year earlier.

There were about a third less crude oil and natural gas wells completed in western Canada during the first nine months of 1992. By the end of September, about 2865 wells had been completed of which about 20% proved to be dry.

Exploration drilling continued to take a back seat behind development activity. Exploration activity representing about 40% of western Canada's well completions fell 38% with natural gas recording the largest drop. Company rationalization programs prompted many producers to concentrate on lower-risk oil development programs.

The industry in western Canada held little hope for an improvement in drilling activity over the remainder of the year. However, early fourth quarter data suggests that drilling activity may be undergoing a modest improvement with about a third more rigs active than a year earlier.

Recently announced changes to Alberta's oil and gas royalty system has led to some cautious optimism. These changes, combined with a boost in the federal tax write-offs on exploration, are expected to increase spending. However, the full impact of these measures may not be felt until some time in 1993 or 1994.

Among announced changes by Alberta to stimulate an increase in activity are a lower base royalty structure; a permanent twelve-month royalty holiday for oil exploration wells; reduced royalties on horizontal re-entry wells and reactivated oil wells; and reduced experimental oil sands royalties.

These royalty changes combined with a recent firming of natural gas prices, favourable interest rates and a lower Canadian dollar (which increases exporters' cash flow) are expected to result in a modest increase in drilling activity over 1992's estimated 29% active rig count and 4800 well completions.

The Canadian Association of Oil Drilling Contractors now expects 143 or 35% of 414 available rigs to be active during 1993 with about 5200 wells completed.

Figure 2.1
Drilling Activity in Western Canada
(Number of Wells)

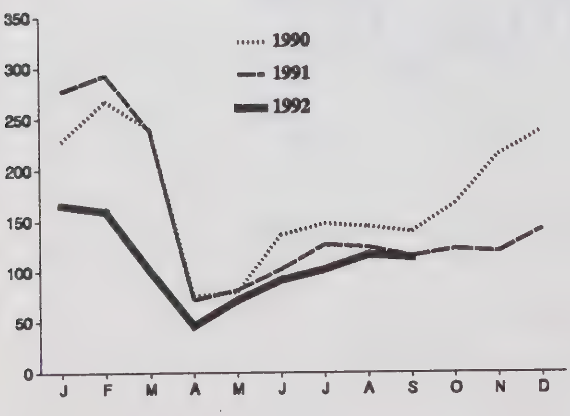
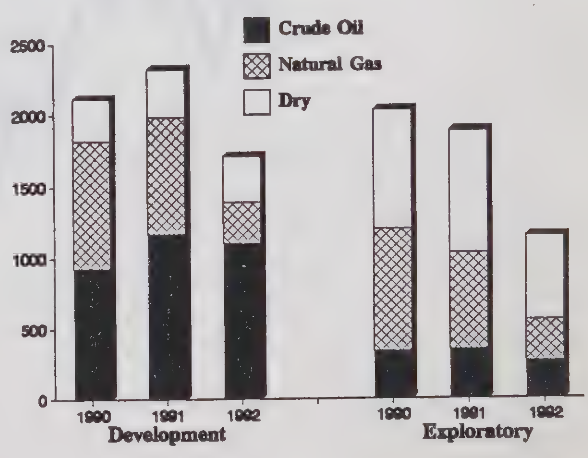


Figure 2.2
Well Completions
(End-of-September)



3. Crude Oil Supply

. Canada produced significantly more crude oil during the third quarter of 1992 due to a rise in conventional light crude oil production as well as improved demand and higher prices for heavy crude oil.

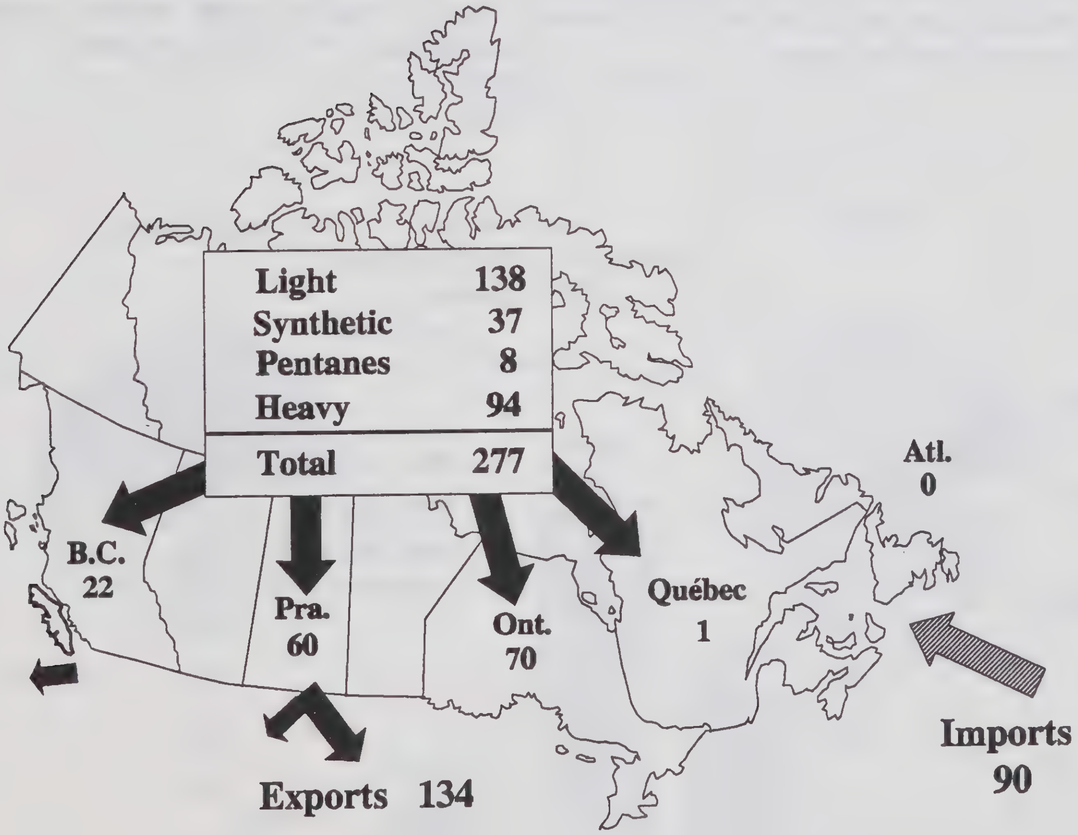
. Crude oil imports into Canada fell during the third quarter as a result of a sizeable drop refinery requirements in the Atlantic region.

3.1 Total Supply

Total crude supply over the first nine months of 1992 averaged 364 000 m^3/d. Supply over the third quarter of the year averaged 380 000 m^3/d, compared with 370 000 m^3/d a year earlier. The equivalent of 134 000 m^3/d of this third quarter volume was delivered to the export market.

Third quarter domestic supply (including production from Ontario, Bent Horn and offshore Nova Scotia, plus surplus NewGrade supply, recycled diluent and inventory change) averaged 290 000 m^3/d. Gross imports averaged 90 000 m^3/d.

Figure 3.1
Supply and Disposition of Crude Oil and Equivalent
(Third Quarter)
000 m^3/d



3.2 Domestic Production

Crude oil production in Canada jumped 14 000 m^3/d or 5% to 277 000 m^3/d during the third quarter of 1992. This happens to be the highest quarterly average since the mid-seventies and reflects an upturn in both light and heavy crude oil output.

The upturn in production occurred despite the continuance of a severe slump in western Canada oil and gas exploration and development drilling. While an excess supply of natural gas and market constraints dampened enthusiasm for gas, crude oil prices remained relatively high and stable since descending from their peak during the Persian Gulf conflict two years ago.

A reversal in the downward trend in conventional light crude production was evident from the 4 000 m^3/d increase to 138 000 m^3/d. The June start-up of the Cohasset/Panuke development off the coast of Nova Scotia coupled with steady supply from western Canada accounted for the increase. Cohasset/Panuke is Canada's first commercial offshore development and should eventually add over 6 000 m^3/d to Canada's conventional light crude oil output.

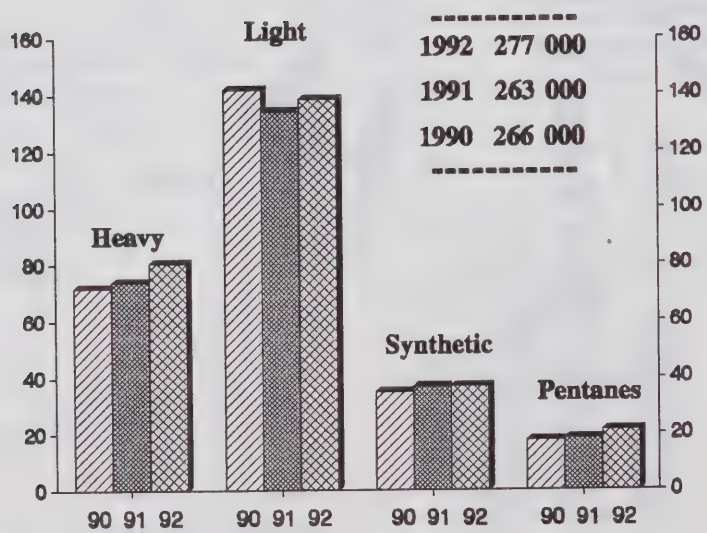
Light crude supply was further bolstered by a 3 000 m^3/d rise in pentanes plus supply. This in turn reflected rising natural gas production, of which pentanes plus is a by-product. On the other hand, output of synthetic light crude from the Canada's two major oil sands projects, Suncor and Syncrude, remained unchanged from last year at 37 000 m^3/d.

The supply of blended heavy crude rose 7 000 m^3/d to approach 94 000 m^3/d. All of the increase was in conventional heavy production with bitumen output remaining unchanged from a year earlier. Demand for heavy crude rose substantially over the last year as a result of increased upgrading capacity at the Conoco refinery in Billings Montana, and more recently, the start-up of the Lloydminster Bi-Provincial Upgrader.

Further gains in heavy crude production is expected in light of the recent announcements by Imperial Oil to start-up two mothballed phases of its Cold Lake bitumen project. Improved crude oil prices and rising upgrader demand has prompted the company to bring phases 7 and 8 on stream during the second quarter of 1993. This will boost bitumen production by an additional 3 000 m^3/d by year-end.

Figure 3.2
Domestic Crude Oil Production
(Third Quarter)

000 m^3/d



3.3 Crude Oil Imports

In the third quarter crude oil imports into eastern Canada fell by 11 000 m^3/d to 90 000 m^3/d. All of the reduction was recorded in the Atlantic region reflecting a decline in refined product demand and a lengthy turnaround at the Come-by-Chance refinery in Newfoundland. In Quebec, there was a slight increase in imports while no significant volume was delivered into Ontario during the quarter.

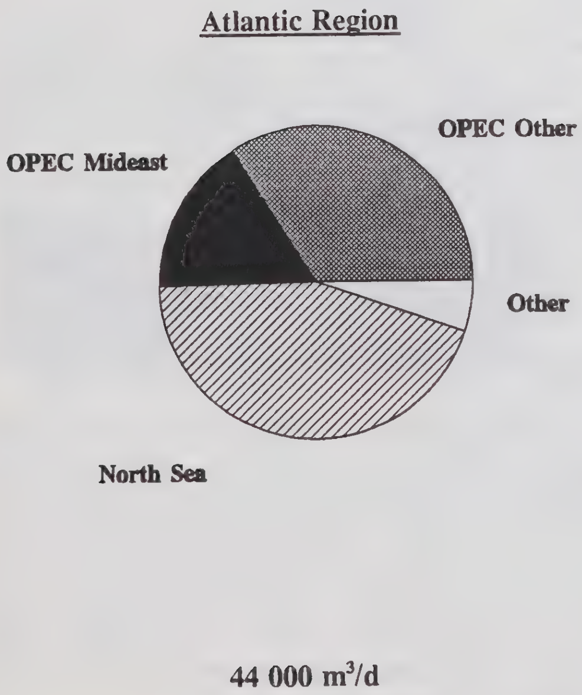
North Sea crudes, principally destined for Quebec refineries, accounted for almost 60% of total imports. Relying entirely on foreign crude oil feedstocks since the closure of the Sarnia-Montreal extension in July of 1991, the Montreal refiners have substituted North Sea and Mexican crude oil in lieu of western Canadian crude. The demand for the heavier Mexican crudes is largely limited to asphalt production.

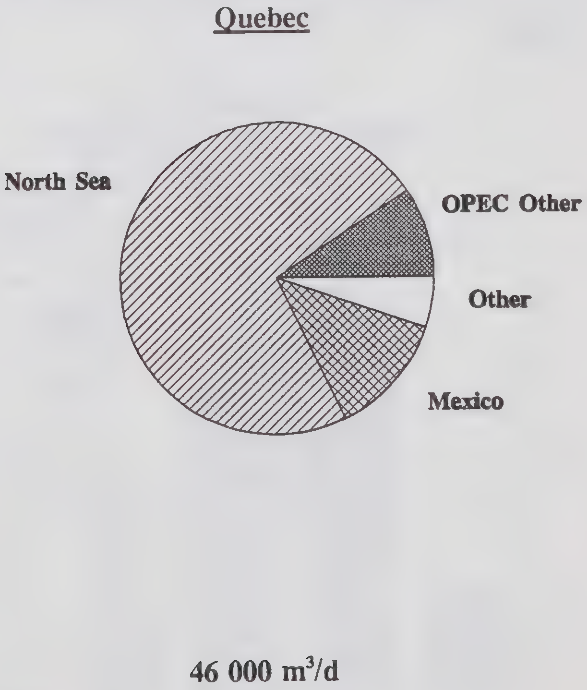
OPEC crudes, half of which were from Saudi Arabia, comprised 30% of total imports. Most OPEC imports continued to be delivered to refineries in the Atlantic region.

After being purged and shut down for almost a year, the Sarnia-Montreal extension was re-activated in July at the request of the Alberta Petroleum Marketing Commission which intends to resume deliveries of western Canadian crude oil to Montreal.

To date, the 365 000 m^3 linefill operation is behind schedule, primarily because of reduced crude oil capacity and apportionment on the Interprovincial pipeline system and additional demand. Crude oil is therefore not expected to reach Montreal until March/April of 1993. In the interim, Quebec refiners will for the most part be dependent of foreign crude feedstocks. However, some deliveries of Scotian (Panuke) light crude are scheduled for the fourth quarter of 1992.

Figure 3.3
Crude Oil Imports by Region
000 m^3/d





4. Crude Oil Disposition

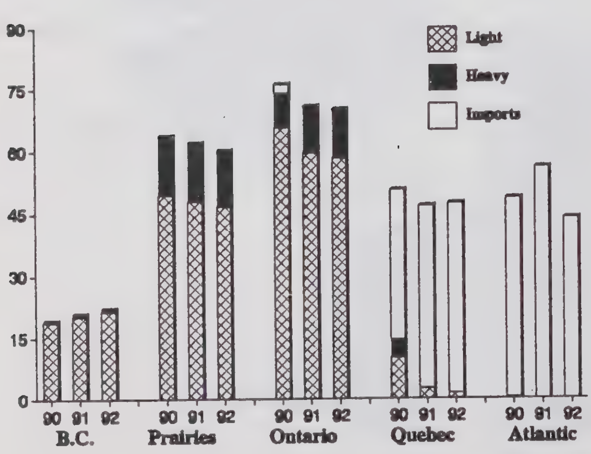
. Crude oil exports surged as domestic refinery feedstock requirements continue to slump.

4.1 Canadian Refinery Crude Oil Receipts

The seasonal upturn in crude oil demand in Canada, normally occurring during the summer months after refineries complete their spring turnarounds, was mitigated somewhat during the third quarter of 1992 by a lengthy turnaround at the Come-by-Chance refinery in Newfoundland, and by the chronic sluggishness in sales pervading across refined product markets in Canada. Although crude oil deliveries to Canadian refineries did rise by almost 28 000 m^3/d from the previous quarter to 244 000 m^3/d, demand nevertheless remained some 13 000 m^3/d below the third quarter of 1991.

Virtually all of the decline in crude oil receipts from the year before occurred in the Atlantic region where there was a complete shutdown of Newfoundland's Come-by-Chance refinery from early August to mid-October. There was relatively little change in demand in the other regions. The drop in receipts in the Atlantic curtailed the level of crude oil imports, which fell by 11 000 m^3/d to 90 000 m^3/d, from the year before.

Figure 4.1
Refinery Crude Oil Receipts
(Third Quarter)
000 m^3/d



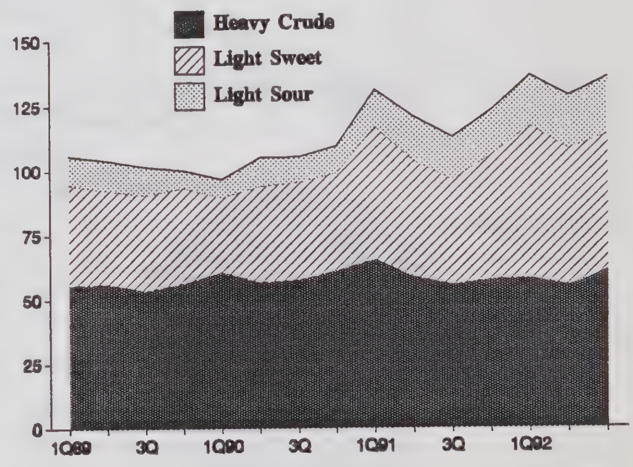
Receipts of domestic crude oil declined by 2 000 m^3/d to 154 000 m^3/d. A drop in deliveries of conventional light crude oil receipts was offset in part by small increases in demand for synthetic crude, condensate and heavy crude oil.

4.2 Crude Oil Exports

The volume of Canadian exports remained high during the third quarter of the year. Averaging 136 000 m^3/d, exports were 23 000 m^3/d or 20% higher than a year earlier. About two thirds of the growth in exports was attributable to the rise in domestic crude oil production. The remainder reflected mainly reduced crude oil demand in Canada.

As has been traditionally the case, almost all Canadian exports were to the United States. About 85% were delivered by pipeline to the U.S. Great Lakes region. Exports of light crude jumped by 17 000 m^3/d to 74 000 m^3/d while there was a 6 000 m^3/d increase to 65 000 m^3/d in heavy crude deliveries.

Figure 4.2
Crude Oil Exports
000 m^3/d



It should be noted that an increasing volume of heavy crude is being blended with light crude at the feeder pipeline stage prior to entering the major trunk lines for delivery to refineries. Currently between 8 000 and 10 000 m^3/d of heavy crude appears to have been blended with light crude streams. This tends to inflate the level of light crude exports while lowering their overall quality. By the same token, the volume of heavy crude exports is deflated commensurately.

5. Pipeline Deliveries

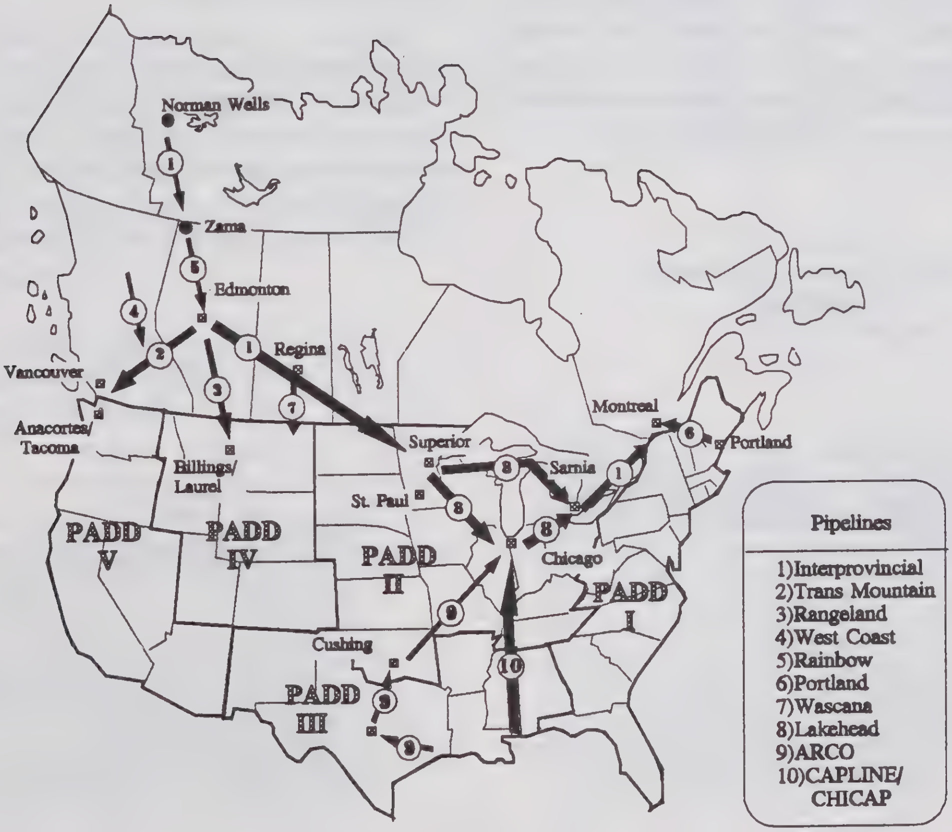
• Interprovincial pipeline crude oil nominations have been subject to high levels of apportionment since October of 1990. Despite industry efforts to address the issue overnominations by the shippers continues.

Most Canadian crude oil is gathered at Edmonton, Alberta. It is then delivered to the domestic and export market, for the most part, by a network of pipelines.

The bulk of Canadian crude oil exports are delivered east into the United States via the Interprovincial and Lakehead pipeline systems. Smaller volumes are delivered by the Trans Mountain to the west coast for delivery to large U.S. refineries in the Puget Sound area and for tankering offshore. The Rangeland pipeline carries crude oil south into Montana.

Canadian crude oil delivered to the U.S. midwest competes in the key Chicago refining area with U.S. domestic crudes and other foreign crudes delivered through the CAPLINE/CHICAP pipeline system from the Louisiana Gulf Coast and alternatively the ARCO pipeline system from the Texas Gulf Coast via Cushing, Oklahoma.

Figure 5
Major Crude Oil Pipelines



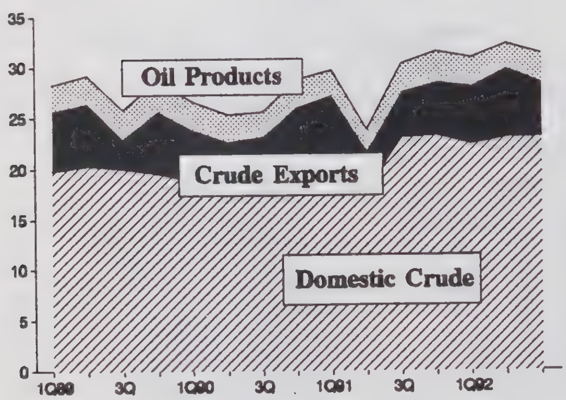
5.1 Trans Mountain Pipeline Deliveries

The Trans Mountain Pipe Line (TMPL) originates at Edmonton and delivers crude oil, semi-refined and refined petroleum products some 1328 kilometres west to the Vancouver area. The pipeline also receives crude from northern British Columbia at Kamloops delivered via the West Coast Pipe Line.

Total deliveries during the third quarter of 1992 averaged 33 000 m^3/d, up 3 000 m^3/d from that recorded a year earlier. Domestic deliveries averaged 26 000 m^3/d of which 23 000 m^3/d (89% crude) was delivered to refineries in the Vancouver/Burnaby area. The remainder composed of refined petroleum products was delivered to Kamloops, British Columbia.

Export deliveries totalled 5 000 m^3/d, up about 1 000 m^3/d from a year earlier. However, deliveries which rose during the first half of 1992 tapered off over the third quarter with the end of the summer gasoline season. Exports tankered offshore via TMPL's Westridge Marine Terminal averaged 2 000 m^3/d with the remainder delivered by a spur pipeline to refiners in the Puget Sound area of Washington State.

Figure 5.1
Trans Mountain Deliveries
000 m^3/d



TMPL expects movements of crude oil to Washington state to be somewhat higher during the fourth quarter of 1992 due to the ongoing problem of apportionment on the Interprovincial Pipe Line system. IPL apportionment is discussed in section 5.3.

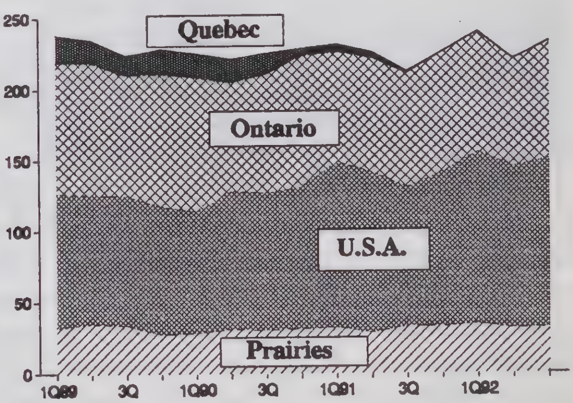
5.2 Interprovincial Pipe Line Deliveries

The Interprovincial Pipe Line (IPL) system consists of three major sections stretching some 3 700 kilometres from western Canada east as far as Montreal, Quebec. The western section of the IPL originates at Edmonton and travels east through Regina, Saskatchewan and crosses the border into the United States near Gretna, Manitoba. The Lakehead portion of the line serves the U.S. Great Lakes region via routes to the north and south of Lake Michigan before they join at Sarnia, Ontario.

The Sarnia to Montreal section, closed since mid-1991, was reactivated in July. The Alberta Petroleum Marketing Commission (APMC), which markets royalty crude for Alberta, intends to resume deliveries of about 3 000 to 5 000 m^3/d of conventional light crude to refineries in Montreal. Line fill (365 000 m^3) began in July although oil is not expected to reach Montreal until March/April 1993.

Nevertheless, IPL deliveries during the third quarter totalled 233 000 m^3/d, 21 000 m^3/d or 10% higher than a year earlier. U.S. destinations received most of the incremental shipments with deliveries totalling 118 000 m^3/d. Deliveries to the Prairies and Ontario averaged 32 000 m^3/d and 83 000 m^3/d respectively.

Figure 5.2.
IPL Deliveries
000 m^3/d



5.3 IPL Apportionment

Pipeline apportionment is normally required when shippers' crude oil nominations exceed the pipeline's capacity to deliver the nominated volumes. Apportionment is, in effect, an alternative to the price mechanism for allocating pipeline space when nominal or actual demand exceeds supply. The price mechanism is precluded as a rationing device because the Canadian pipeline industry is regulated by the National Energy Board (NEB) and tolls are fixed on a cost of service basis.

Except for April 1992, IPL has consistently had to apportion pipeline space since October 1990. This is in stark contrast to the previous 18 months when there was virtually no apportionment. In December alone, IPL imposed an apportionment of 33%. The figure below illustrates the monthly levels of apportionment since October, 1990.

IPL apportionment has reflected a number of developments over the last two years. In late 1990 and early 1991, apportionment was required to balance a price-induced surge in Canadian crude oil production during the Persian Gulf conflict with reduced pipeline capacity after IPL had undertaken a major inspection and maintenance program on the western Canadian portion of its system.

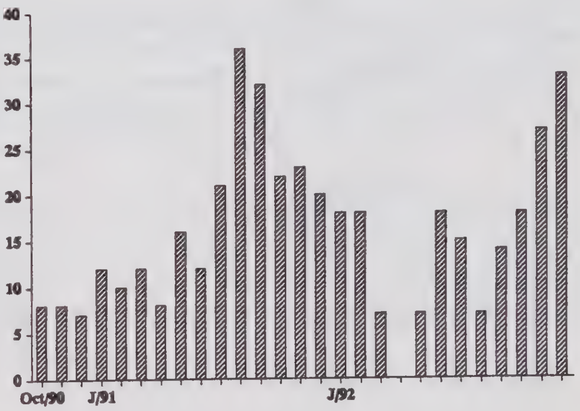
IPL's system capacity might have returned to normal had not Lakehead's line 3 sprung a leak near Grand Rapids, Minnesota in March of 1991. The U.S. Department of Transport subsequently limited throughput on line 3 pending the completion of a major inspection program involving hydrostatic testing on the U.S. portion of the line. The inspection program was completed in the fall of 1992.

It became evident as the apportionment levels grew during 1991 that part of the problem stemmed from shippers inflating their nominations in an attempt to reserve line space. In October of 1991, IPL met with producers and shippers to discuss a proposal to resolve the overnomination problem. This was known as the Historical Average Pumping proposal. However, it was generally viewed by industry as being restrictive to market flexibility.

Subsequently, an industry working committee developed nomination procedures that would identify shippers who were inflating their nominations. The offending shippers would then be penalized by restricting their access to the major pipelines in the following month. The new rules were approved by the NEB and went into effect in March 1992. The rules appear to have only been partially effective, as suggested by the figure below.

It is important to note that not only has IPL been operating at reduced capacity for most of the last two years, but that there has also been a significant rise in the excess supply of domestic crude oil. Canadian crude oil production is about 8 000 m^3/d higher than it was two years ago while western Canadian refinery demand for crude has fallen by about 5 000 m^3/d, reflecting the recession. This has put increased pressure on the IPL system, specifically that part serving the U.S. midwest (PAD District II). IPL deliveries of crude oil exports to PADD II have risen by over 20 000 m^3/d over the same two year period. It also should be noted that, overnominations notwithstanding, IPL's throughput has generally been close to its available capacity.

Figure 5.3
IPL Apportionment
percent

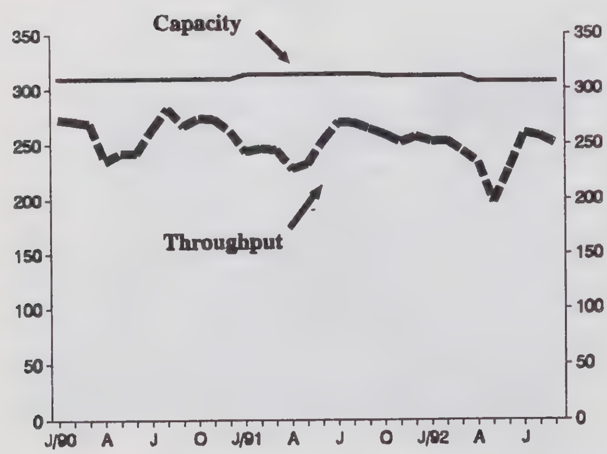


6. Refinery Activity

. The national refinery utilization rate for the third quarter of 1992 averaged 83%. Most of the decline from last year occurred in the Atlantic region as a result of a prolonged turnaround at the Come-by-chance refinery.

Refinery throughput will normally diverge from refinery crude oil receipts for two reasons. First, feedstocks other than crude oil are also charged in the refining process. Some of the 'other' feedstocks include gas plant butanes (used mostly by Prairie refineries) and partially processed oil (used mostly by refineries in British Columbia). During the third quarter of 1992, these 'other' receipts averaged almost 11 000 m^3/d, accounting for about 4% of total refinery feedstock receipts in Canada. Second, refinery throughput reflects changes in feedstock inventories. Other things being equal, an inventory drawdown will cause refinery throughput to exceed receipts - and vice versa in the case of an inventory build. Over the quarter, crude oil inventories at the national level were drawn down at a rate of more than 1 000 m^3/d.

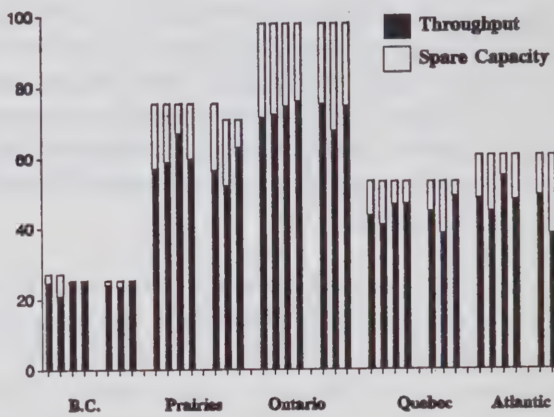
Figure 6.1
Total Capacity and Utilization
000 m^3/d



Total throughput averaged 256 000 m^3/d during the third quarter, about 12 000 m^3/d below the same quarter last year. Turnaround problems, at the Come-by-Chance refinery in Newfoundland accounted for most of the drop in throughput.

With Canadian refining capacity estimated to have fallen to about 307 000 m^3/d, the level of throughput achieved during the third quarter meant a national refinery utilization rate of about 83%. This corresponded to a drop of 3 percentage points from the previous year. The drop might have been larger still had there not also been a 4 500 m^3/d reduction in Canadian refining capacity when the Turbo refinery in Alberta was closed permanently last May.

Figure 6.2
Regional Capacity and Utilization
(1st Quarter 1991 to 3rd Quarter 1992)
000 m^3/d



The utilization rate was highest in British Columbia where it reached nameplate capacity, and lowest in the Atlantic region where it fell to 73%. The figure below illustrates refinery throughput and capacity by region, starting from the first quarter of 1991.

7. Crude Oil and Petroleum Product Stocks

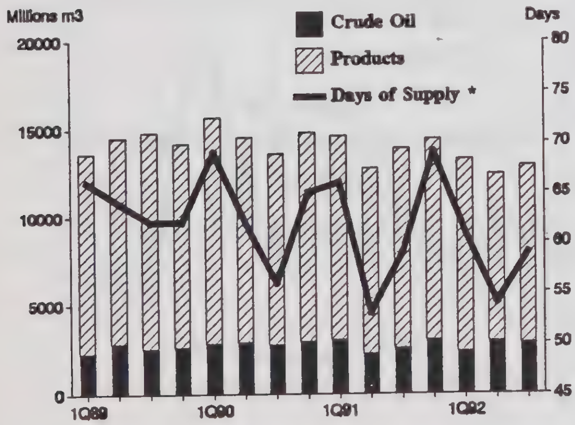
. A sluggish market for refined petroleum products largely explains the decline in product inventories.

Total crude oil and refined petroleum products held by refineries and major distributors totalled 12.9 million m^3 at the end of the third quarter of 1992. This was down from 13.8 million m^3 recorded a year earlier.

Of this volume, refined petroleum product stocks at 10.1 million m^3 were down 1.3 million m^3 or 11% from a year earlier. However, stocks were up 6% from the previous quarter as routine spring refinery maintenance programs ended. Crude oil stocks, on relatively small volumes, were up 0.3 million m^3 or 12% to 2.9 million m^3.

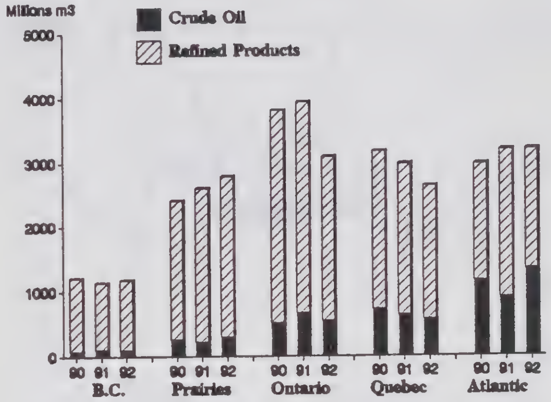
Refined product stocks fell across all regions with exception of the Prairies and British Columbia. Ontario recorded the largest decrease, falling some 733 000 m^3 or 21% as end-of-quarter demand for refined products remained sluggish. In Quebec, stocks were down 281 000 m^3 or 12% to 2.1 million m^3.

Figure 7.1
Crude Oil and Petroleum Product Stocks
(end-of-quarter)



Stocks of 'main' petroleum products including motor gasoline, distillates and heavy fuel oil, totalling 6.4 million m^3 were down 1.6 million m^3 or 20% from the year before. Motor gasoline stocks led the way, down 678 000 m^3 or 20% to 2.6 million m^3. Distillates were down 400 000 m^3 or 23% to 3.0 million m^3.

Figure 7.2
Crude and Petroleum Product Stocks by Region
(end-of-quarter)



End-of-September total crude oil and refined product stocks represented about 59 days of supply (based on historical consumption), the same level calculated a year earlier. Stocks of 'main' products fell to 36 days of supply from 42 days.

** Stocks do not include estimates of crude oil held in pipelines and tankage. If these stocks were to be included in the calculation, it is estimated that the number of days of supply would increase by about 7 days to 66 days.*

Figure 7.3
Total Petroleum Product Stocks
thousands of m³

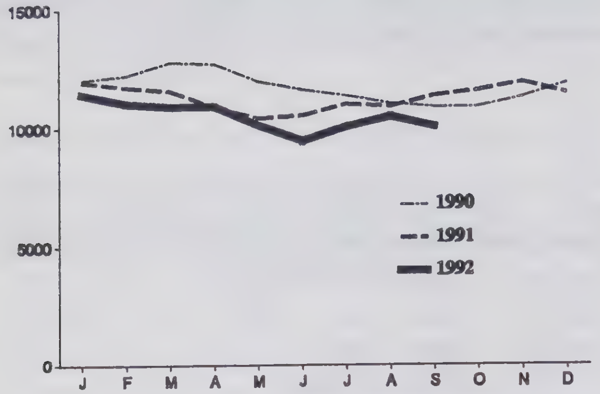


Figure 7.4
Motor Gasoline Stocks
thousands of m³

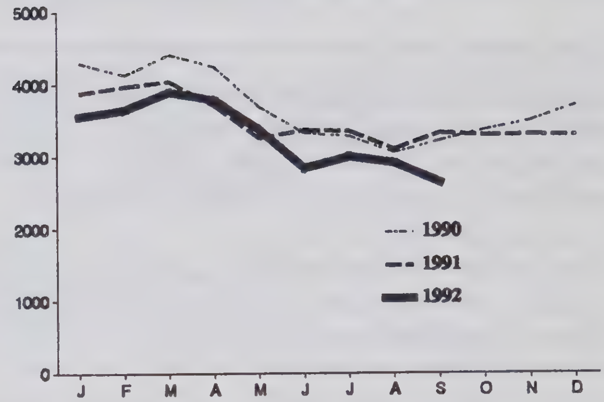


Figure 7.5
Light Fuel Oil Stocks
thousands m³

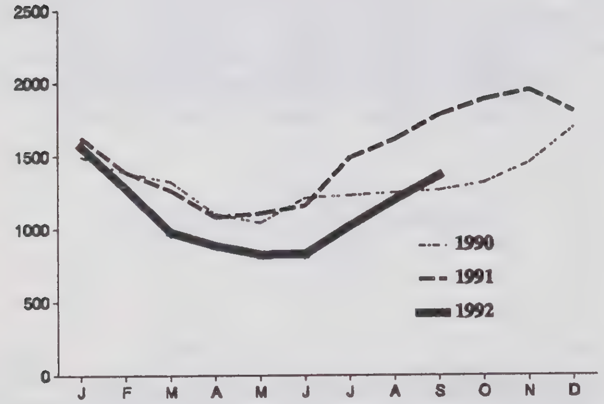


Figure 7.6
Diesel Fuel Oil Stocks
thousands m³

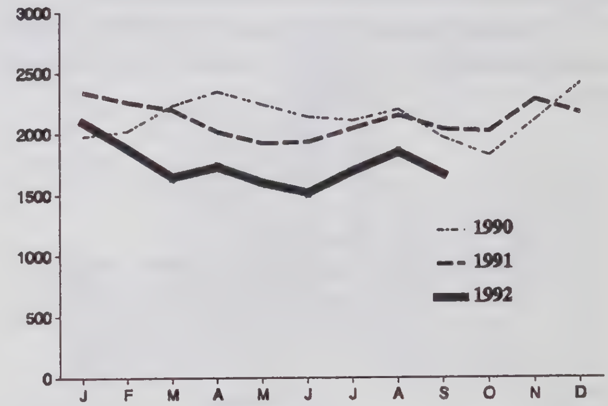


Figure 7.7
Heavy Fuel Oil Stocks
thousands m³

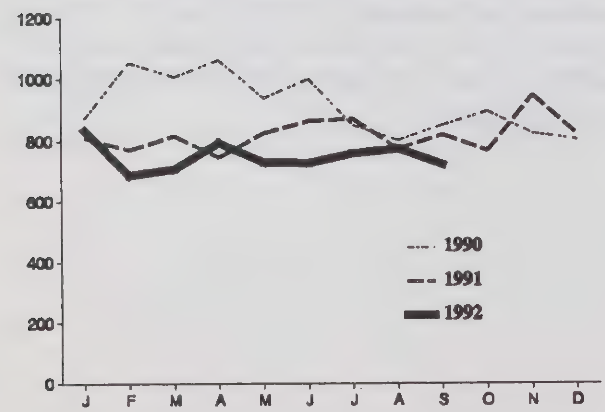
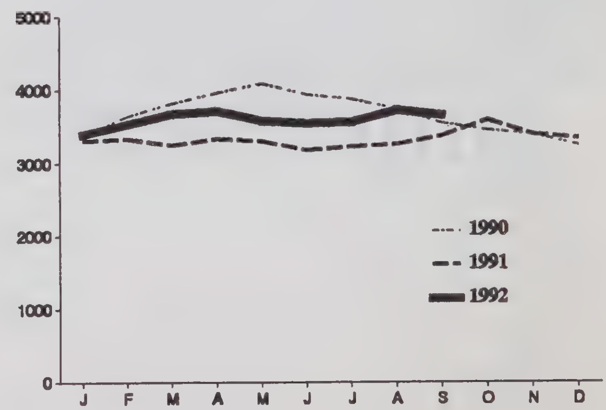


Figure 7.8
Other Petroleum Product Stocks
thousands m³



8. Crude Oil Prices

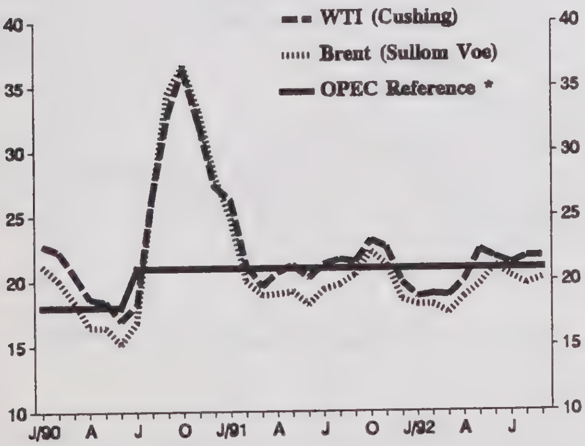
. International and domestic crude oil prices continue to be affected by OPEC production quotas and sluggish petroleum product demand.

8.1 International Crude Oil Prices

Spot crude oil prices on the international market continued to fluctuate over the third quarter of 1992. In late July and early August, prices came under pressure due to sluggish petroleum product demand in the United States and reports of extremely high OPEC crude oil production. The resulting buildup in petroleum stocks undermined prices throughout August.

Spot crude oil prices strengthened somewhat in September, reflecting the upturn in seasonal petroleum product demand in the United States and reports of a drawdown in crude oil inventories. As well, the market expected OPEC to agree to support price increases at its September 17 meeting. However, by the end of September, spot crude oil prices began to decline, reflecting OPEC's decision to set its fourth quarter production ceiling at 24.2 million barrels/day and reports indicating large builds of crude oil inventories.

Figure 8.1
International Crude Oil Prices
US$/barrel

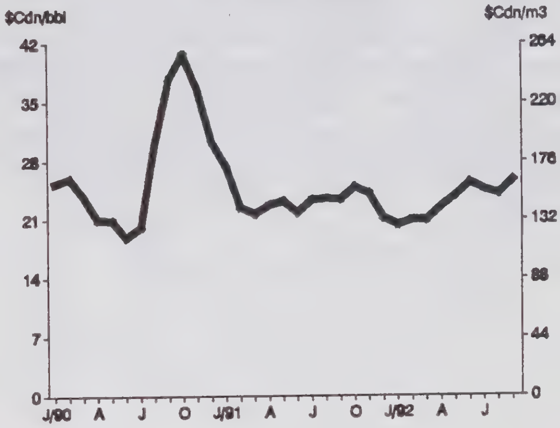


Over the third quarter, the spot price for West Texas Intermediate (WTI) averaged US$21.65/bbl, about $0.20/bbl above third quarter 1991 and $0.55/bbl higher than for the previous quarter.

8.2 Domestic Crude Oil Prices

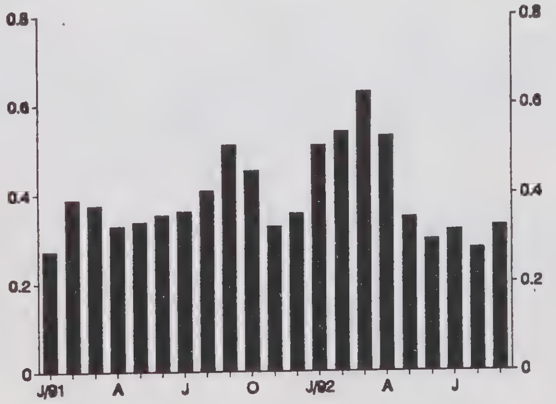
As illustrated in figure below, domestic crude oil prices tend to follow trends established in the international market. The possibility of OPEC production quotas combined with some local (Canadian and U.S. midwest) market conditions helped to push the posted price of Canadian Par crude up to $25.72/bbl ($161.03/m^3) by the end of the third quarter. The was the highest monthly average price since January 1991.

Figure 8.2.1
Canadian Par Crude Oil Postings
(At Edmonton)



Over the quarter, Canadian Par crude averaged $24.81/bbl ($156.13/m^3), up $0.86/bbl above the previous quarter. At the same time, the average Canadian Par crude to WTI price differential narrowed from the previous quarter by about US$0.08/bbl to US$0.31/bbl ($3.84/m^3).

Figure 8.2.2
Canadian Par Crude vs WTI (NYMEX)
US$/barrel



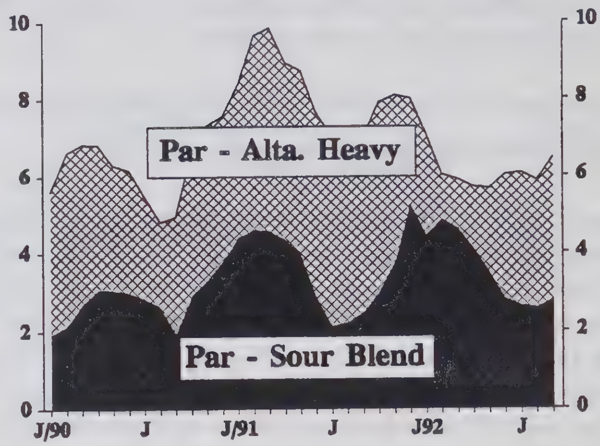
8.3 Domestic Crude Oil Price Differentials

Figure 8.3 illustrates the average monthly Canadian Par crude oil price compared to average Alberta Light Sour Blend postings. Similarly, Canadian Par is compared with Alberta heavy crude oil.

Domestic price differentials, following sharp increases late in 1991, continued to narrow. In the third quarter of 1992, differentials returned to more traditional levels with the light sour crude differential representing about half of the heavy to par crude price differential.

The light sour to par crude differential narrowed significantly from about $4.65/bbl ($29.29/m^3) in the first quarter of 1992 to $2.69/bbl ($16.95/m^3) only to increase late in the third quarter following seasonal trends. The heavy crude differential, after a modest second quarter decrease due to strong demand for heavy crudes in the United States, widened to $6.13/bbl ($38.61/m^3).

Figure 8.3
Domestic Crude Oil Price Differentials
CDN$/barrel



9. Refined Petroleum Product Prices

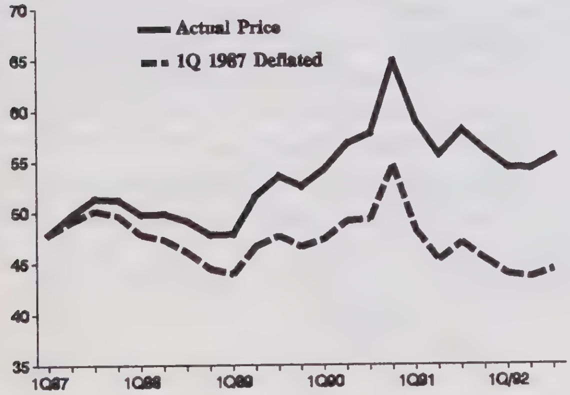
• ***Although higher taxes in Canada account for about 85% of the Canada/U.S. motor gasoline price differential, improved economies of scale have also contributed to lower prices paid by Americans compared to Canadians.***

9.1 Domestic Price Trends

The average pump price of regular unleaded motor gasoline in the third quarter of 1992 was 55.5 cents/litre, an increase of 1.1 cents/litre over the previous quarter. After reaching an average price of 56.8 cents/litre in July, prices decreased over the following two months, to close out the quarter with an average of 54.6 cents/litre in September.

In spite of increases in the second quarter and beginning of the third quarter, average regular gasoline prices for the first nine months of 1992, at 57.6 cents/litre, were 3.2 cents/litre lower than the same period in 1991.

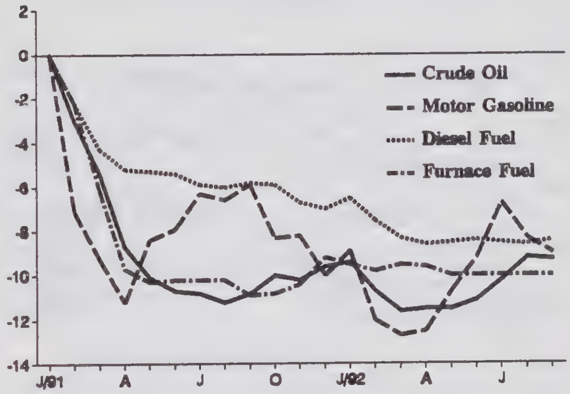
Figure 9.1
Regular Unleaded Gasoline Prices
cents/litre



The average diesel price remained stable from the second to the third quarter of 1992 at 52.8 cents per litre. In contrast to gasoline, the price for the first nine months of 1992 increased 3.3 cents/litre compared to the same period last year.

The following graph illustrates the evolution of retail petroleum product prices from January 1991. Motor gasoline prices peaked in the summer months during the height of the driving season, when demand is traditionally the highest. Crude oil prices also increased in the third quarter, reaching levels not experienced since April 1991.

Figure 9.2
Cumulative Price Changes
(since January 1991)
cents/litre



9.2 Consumption Taxes On Petroleum Products

The sum of federal and provincial taxes on regular and unleaded gasoline was 25.9 cents/litre in the third quarter of 1992, down 0.1 cents/litre from the second quarter.

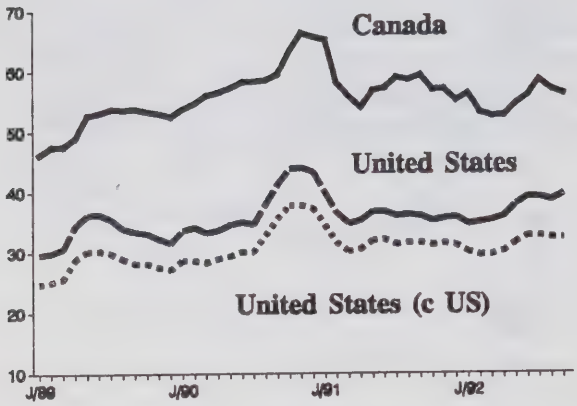
During the third quarter, provincial taxes decreased on three grades of gasoline and on diesel fuel in both Prince Edward Island and Nova Scotia. These changes were the result of quarterly reviews.

In an effort to create a market for automobile propane in Newfoundland, the provincial government reduced the tax on propane to 7.0 cents/litre from 13.7 cents/litre on August 17.

9.3 Motor Gasoline Retailing (Canada vs U.S.A.)

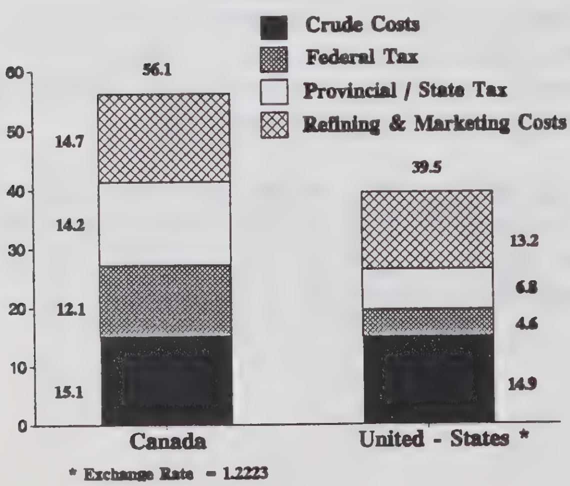
The average price spread between the two countries was 18.1 cents/litre during the third quarter of 1992 an increase of 1.4 cents/litre from the second quarter. The average Canadian price of motor gasoline went up 2.8 cents/litre while the average American price increased 1.4 cents/litre.

Figure 9.3.1
Average Retail Price of Motor Gasoline
(Canada vs U.S.A.)
cents/litre



Crude oil costs increased 1.8 cents/litre in Canada during the third quarter of 1992, while they increased 2.0 cents/litre on average in the United States. Higher taxes in Canada accounted for 85% of the price differential in the third quarter of 1992, a decrease of 6% over the last quarter.

Figure 9.3.2
Breakdown of Average Pump Price
(September 1992)
cents/litre



Although taxes are by far the biggest reason for the variation in the price of motor gasoline between Canada and the United States a recent *Canadian Oil Markets and Emergency Planning Division* report * suggests that improved industry efficiencies have also contributed to lower motor gasoline prices paid by Americans over the last decade compared with Canadians.

Canada vs United States (1980-1990)

According to the report, Canada and the United States experienced significantly different trends in motor gasoline demand during the 1980s. In the United States, gasoline demand increased steadily during the decade and by 1990 it was 10% higher than in 1980. In Canada, however, the trend was different from that in the United States. Demand decreased during the first half of the decade and by 1985 was 15% below the 1980 level. In spite of some increases during the last half of the decade, Canadian demand registered a 12% decline for the period 1980 to 1990.

Factors which can influence gasoline demand include the number and efficiency of automobiles and the price of gasoline. While demand fell in Canada during the 1980s and increased in the United States, the number of automobiles in each country grew during the decade.

In Canada the number of automobiles increased 2.4 million (23%) while in the United States there were 23.3 million more automobiles (up 19%). Despite an increase in the number of automobiles in both countries during the 1980s, the number of retail gasoline outlets fell by 5000 in Canada and 47,000 in the United States. In the United States, the rate of outlet rationalization continues to outpace Canada's. The net result of the outlet rationalization and increased number of automobiles is 228 more cars per outlet on average in Canada in 1990 compared to 1980. In the United States average cars per outlet increased by 531.

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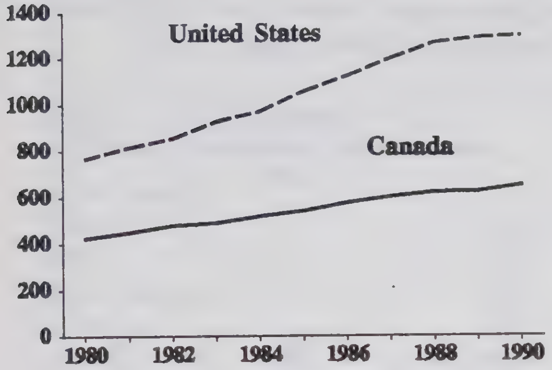
* ***A Review of Gasoline Retailing, Canada vs United States (Update 1980-1990)****; October 1992, Canadian Oil Markets and Emergency Planning Division.*

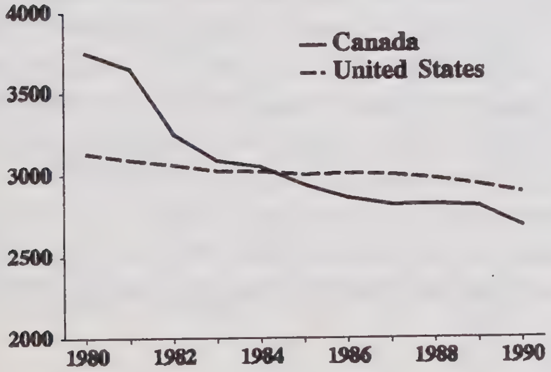
Figure 9.3.3
Number of Automobiles per Outlet



Not only were there more automobiles on the road in 1990 compared to 1980, but the average distance travelled in any one year also increased. Between 1982 and 1988, the average distance travelled by automobile in Canada and the United States increased 11% and 7%, respectively. However, during any one year Canadians drove further than their American counterparts, 7% further in 1988.

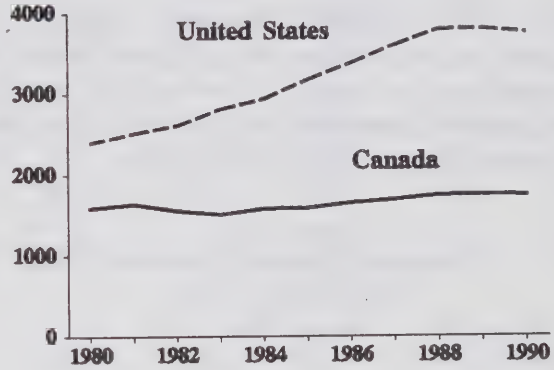
Despite the increased number of automobiles and the longer distances driven, a significant increase in automobile efficiency resulted in a reduction in average fuel consumption. The decline in gasoline sales per automobile was more dramatic in Canada than in the United States. In Canada, average consumption declined 1063 litres or 28%, while in the United States the decline was 241 litres or 8%. In 1990, automobiles in Canada used about 200 litres less fuel per year than automobiles in the United States.

Figure 9.3.4
Gasoline Sales per Passenger Vehicle
litres



Although the number of retail outlets and the gasoline consumption per automobile fell, the percentage reduction in outlets was greater than the percentage reduction in average sales per automobile. As a result, the average sales of gasoline per outlet increased. By 1990, average sales per outlet were up 56% in the United States and 10% in Canada. The growth in average sales was fairly steady in the United States. In Canada average sales declined slightly at the beginning of the decade, with modest growth after 1983.

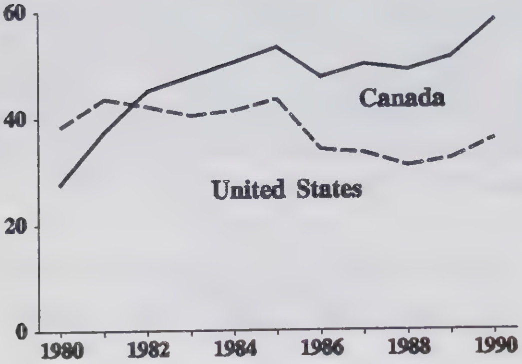
Figure 9.3.5
Average Yearly Sales per Retail Outlet
m^3



In 1980, the average sales per outlet in the United States was about 50% higher than that in Canada. However, by the end of the decade, larger efficiency gains experienced in the United States resulted in average sales per outlet being more than twice that of the average Canadian outlet. Higher average sales per outlet means that the fixed costs of running the outlet are spread over larger volumes. This results in lower per unit costs, and either lower prices for the consumer and/or a higher return for the owner of the outlet. An outlet with a higher output can be more competitive and is more likely to survive the hard times than an outlet with a lower sales volume, all other factors being the same.

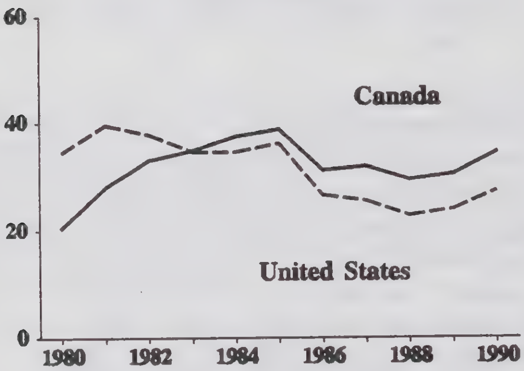
Lower prices for American consumers are one of the benefits of higher average gasoline sales per retail outlet. Figure 9.3.6 shows that consumers in the United States have enjoyed lower prices than Canadians for regular unleaded gasoline since 1982.

Figure 9.3.6
Regular Unleaded Gasoline
(including taxes)
cents/litre



Much of the difference between Canadian and American prices is attributable to higher federal and provincial taxes in Canada. However, even when the impact of taxes is removed, prices in the United States were below those in Canada since 1983.

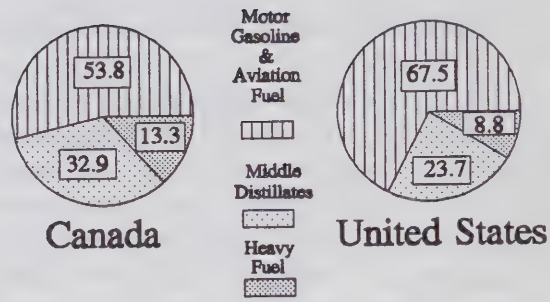
Figure 9.3.7
Regular Unleaded Gasoline
(excluding taxes)
cents /litre



Other factors can contribute to the lower gasoline prices which consumers pay in the United States. American refineries are, on average, larger and more sophisticated than refineries in Canada. Also, the population of the United States is almost ten times that of Canada, while the geographic mass is slightly smaller. Transportation costs are lower in the United States because the consumer is closer to the product source. All of these economies of scale which American refiners and marketers enjoy contribute to lower retail prices for American consumers.

The average product slate produced by refiners also affects the cost of petroleum products. The product mix in the United States has a higher proportion of motor gasoline and aviation fuel (68%) than the mix flowing from Canadian refineries (54%).

Figure 9.3.8
Sales of Main Petroleum Products
1990



However, the crude refined in the United States tends to be heavier than that refined in Canada. In order to produce the lighter slate in the United States the refining processes must be more rigorous than those used in Canada. Some of the economies of scale gained from the larger refineries operating in the United States are offset by the higher refining costs associated with the more rigorous refining processes.

Product demand also influences the product mix. In Canada there is a higher demand for distillates and heavy fuel oil than in the United States. Our colder winters and resultant need for heating fuels is the primary reason. Lighter products (motor gasoline and aviation fuel) sell for a higher price than heavier products (middle distillates and heavy fuel oil). The higher the proportion of light product for sale, the earlier the fixed costs of refining the crude oil are covered. As a result, retailers in the United States may be able to afford to sell gasoline for less than retailers in Canada.

Appendix I
Production of Crude Oil and Equivalent
(000 m^3/d)

	1991 2Q	1991 3Q	1991 4Q	1991 Year	1992 1Q	1992 2Q	1992 3Q
A. Light and Equivalent							
Conventional							
Alberta	110.1	110.2	112.5	112.2	115.3	110.2	110.2
B.C.	5.3	5.5	5.7	5.5	5.5	5.5	5.5
Saskatchewan	11.0	10.5	11.4	11.4	11.4	11.4	11.1
Manitoba	1.9	1.9	1.9	1.9	1.8	1.8	1.9
NWT	5.2	5.2	5.2	5.2	5.3	5.3	5.6
Ontario	0.7	0.6	0.6	0.6	0.6	0.6	0.6
Nova Scotia	-	-	-	-	-	0.6	3.5
Total	**134.2**	**133.9**	**137.3**	**136.5**	**138.3**	**135.4**	**138.3**
Synthetic							
Suncor	10.0	9.4	9.1	9.6	10.2	6.4	9.9
Syncrude	22.8	27.4	29.6	26.3	27.6	26.4	27.1
Total	**32.8**	**36.8**	**38.7**	**35.9**	**37.8**	**32.8**	**37.0**
Pentanes Plus (excl. diluent)	**6.6**	**5.6**	**9.0**	**8.6**	**9.7**	**7.4**	**8.1**
Total Light	**173.6**	**176.3**	**185.0**	**179.3**	**187.4**	**175.6**	**183.4**
B. Heavy Crude							
Alberta							
Conventional	30.0	30.0	32.1	30.6	32.8	31.9	33.8
Bitumen	18.8	21.5	16.5	19.5	18.4	20.6	21.7
Diluent	8.3	9.8	8.6	9.3	8.9	9.4	9.4
Total	**57.1**	**61.3**	**57.2**	**59.4**	**60.1**	**61.9**	**65.1**
Saskatchewan							
Conventional	21.1	22.2	23.4	22.3	23.4	24.0	25.0
Diluent	2.8	2.9	3.3	3.1	3.4	3.4	3.5
Total	**23.9**	**25.1**	**26.7**	**25.4**	**26.8**	**27.4**	**28.5**
Total Heavy	**81.0**	**86.4**	**83.9**	**84.8**	**86.9**	**89.3**	**93.6**
C. Total Production	**254.6**	**262.7**	**268.9**	**264.1**	**274.3**	**264.9**	**277.0**

Appendix II
Supply and Disposition of Crude Oil and Equivalent
(000 m^3/d)

	1991				1992		
	2Q	3Q	4Q	Year	1Q	2Q	3Q
A. Light and Equivalent							
Supply							
Production	173.5	176.3	185.0	179.4	187.5	175.5	183.3
Newgrade	0.3	2.2	3.3	2.0	3.4	0.7	2.1
Draw/(Build) *	9.8	8.9	8.1	8.1	11.8	9.9	16.6
Net Supply	183.6	187.4	196.4	189.5	202.7	186.1	202.0
Domestic Demand							
Atlantic	0	0	0	0	0	0	0
Quebec	3.2	2.6	0	2.7	0	0	1.4
Ontario	56.2	59.6	63.0	58.8	61.3	51.0	58.5
Prairies	46.0	47.9	47.8	46.6	43.2	40.5	46.5
B.C.	16.5	20.3	20.4	18.9	20.0	21.2	21.4
Total	121.9	130.3	131.1	127.0	124.4	112.7	127.8
Exports	61.8	57.0	65.2	62.4	78.3	73.4	74.3
Total Demand	**183.7**	**187.3**	**196.3**	**189.4**	**202.7**	**186.1**	**202.1**
B. Heavy Crude (Blended)							
Supply							
Production	81.1	86.4	83.9	84.7	86.9	89.4	93.7
Recycled Diluent	1.3	1.5	0.5	1.0	1.3	1.6	2.1
Draw/(Build) *	(4.7)	(6.2)	(5.9)	(5.0)	(12.9)	(15.1)	(8.0)
Net Supply	77.7	81.7	78.5	80.7	77.7	75.9	87.8
Domestic Demand							
Atlantic	0	0	0	0	0	0	0
Quebec	0	0	0.1	0.1	0	0	0
Ontario	11.4	10.9	9.3	10.2	7.7	11.2	11.6
Prairies	6.7	14.4	10.7	10.3	11.4	8.9	13.9
B.C.	0.5	0.7	0.7	0.6	0.6	0.5	0.9
Total	18.7	25.9	20.8	21.1	19.6	20.6	26.3
Exports	58.9	55.7	57.8	59.6	58.1	55.3	61.4
Total Demand	**77.6**	**81.6**	**78.6**	**80.7**	**77.7**	**75.9**	**87.7**

* *includes statistical error*

Appendix III
Crude Oil Exports by Destination
(000 m³/d)

		1991 2Q	1991 3Q	1991 4Q	1991 Year	1992 1Q	1992 2Q	1992 3Q
U.S. PAD Districts *								
I	Light	6.8	8.9	6.8	7.2	7.4	8.3	8.1
	Heavy	1.0	1.0	1.5	1.3	1.3	1.4	1.6
	Total	**7.8**	**9.9**	**8.3**	**8.5**	**8.7**	**9.7**	**9.7**
II	Light	42.2	34.1	44.5	41.9	53.6	51.6	48.7
	Heavy	54.3	48.3	49.2	51.8	53.5	48.6	54.4
	Total	**96.5**	**82.4**	**93.7**	**93.7**	**107.1**	**100.2**	**103.1**
III	Light	0	0	0	0	0	0	2.4
	Heavy	0	0.6	2.5	1.5	0	0	0
	Total	**0**	**0.6**	**2.5**	**1.5**	**0**	**0.8**	**2.4**
IV	Light	10.5	12.2	12.3	11.1	13.0	8.7	10.4
	Heavy	2.2	3.7	3.4	3.0	2.5	4.9	4.7
	Total	**12.7**	**15.9**	**15.7**	**14.0**	**15.5**	**13.6**	**15.1**
V	Light	1.3	1.8	0.9	1.3	2.5	2.9	3.1
	Heavy	0.7	0.4	0.4	0.5	0	0.5	0.7
	Total	**2.0**	**2.2**	**1.3**	**1.8**	**2.5**	**3.4**	**3.8**
Total U.S.	**Light**	**60.8**	**57.0**	**64.5**	**61.5**	**76.5**	**72.3**	**72.7**
	Heavy	**58.2**	**54.0**	**57.0**	**58.0**	**57.3**	**55.4**	**61.4**
	Total	**119.0**	**111.0**	**121.5**	**119.5**	**133.8**	**127.7**	**134.1**
Offshore	Light	0.8	0	0.9	0.6	1.5	1.1	1.5
	Heavy	0.8	1.7	0.9	1.4	0.9	0	0
	Total	**1.6**	**1.7**	**1.8**	**2.0**	**2.4**	**1.1**	**1.5**
Total	**Light**	**61.6**	**57.0**	**65.4**	**62.1**	**78.0**	**73.4**	**74.2**
	Heavy	**59.0**	**55.7**	**57.9**	**59.4**	**58.2**	**55.4**	**61.4**
	Total	**120.6**	**112.7**	**123.3**	**121.6**	**136.2**	**128.8**	**135.6**

* *U.S. Petroleum Administration for Defense (PAD) Districts*

Appendix IV
Pipeline Deliveries
(000 m^3/d)

	1991 2Q	1991 3Q	1991 4Q	1991 Year	1992 1Q	1992 2Q	1992 3Q
A. Trans Mountain Pipe Line (TMPL)							
Domestic Deliveries							
Light Crude	14.1	18.7	19.7	16.8	19.0	21.1	20.2
Heavy Crude	0.2	1.1	0.3	0.5	0	0.2	0.3
Semi Refined Products	3.7	3.2	3.2	3.9	3.1	1.7	2.6
Refined Products	2.0	2.7	2.9	2.5	2.7	2.4	2.8
Total	20.0	25.7	26.1	23.7	24.8	25.4	25.9
Foreign Deliveries							
Tankers	2.2	3.5	4.5	4.0	4.0	4.6	2.3
Puget Sound Area	1.6	1.0	0.8	1.1	1.7	2.2	3.0
Total	3.8	4.5	**5.3**	**5.1**	5.7	6.8	5.3
Total TMPL	**23.8**	**30.2**	**31.4**	**28.8**	**30.4**	**32.2**	**32.8**
B. Interprovincial Pipe Line (IPL)							
Domestic Deliveries							
Light Crude	74.8	73.1	74.3	74.1	74.0	63.3	67.9
Heavy Crude	12.3	16.0	14.5	13.8	13.6	15.4	17.8
Other (1)	26.5	25.4	28.1	27.2	31.3	28.6	29.3
Total	113.6	114.5	116.9	115.1	118.9	107.3	115.0
Foreign Deliveries							
Light Crude	49.6	42.6	51.4	49.5	59.5	58.0	56.7
Heavy Crude	55.3	49.5	50.6	53.2	54.8	50.1	56.0
Other (1)(2)	7.8	5.6	7.0	6.7	6.6	5.5	5.4
Total	112.7	97.7	109.0	109.4	120.9	113.6	118.1
Total IPL	**226.1**	**212.2**	**225.9**	**224.5**	**239.8**	**220.9**	**233.1**
C. Pipelines to Montreal							
IPL Deliveries							
To Montreal	4.2	1.0	0	2.4	0	0	0
For Export/Transfer	0	0	0	0	0	0	0
Total IPL	4.2	1.0	0	2.4	0	0	0
Portland-Montreal							
Montreal Imports (3)	22.4	24.4	29.1	25.0	28.4	20.8	29.3
Total Montreal Receipts	**26.6**	**25.4**	**29.1**	**27.4**	**28.4**	**20.8**	**29.3**

(1) includes petroleum products and NGL's. *(3) may include cargos imported directly into Montreal*
(2) includes US domestic crudes delivered to the U.S.

Appendix V
Canadian Refinery Receipts
(000 m^3/d)

		1991				1992	
	2Q	3Q	4Q	Year	1Q	2Q	3Q
A. Domestic Receipts							
Light & Equivalent							
Atlantic	0	0	0	0	0	0	0
Quebec	3.1	2.6	0	0	0	0	1.4
Ontario	56.2	59.6	63.0	58.9	61.3	51.0	58.4
Prairies	46.0	47.9	47.7	46.7	43.2	40.5	46.6
B.C.	16.5	20.3	20.4	18.8	19.9	21.2	21.4
Total	**121.8**	**130.4**	**131.1**	**124.4**	**124.4**	**112.7**	**127.8**
Heavy							
Atlantic	0	0	0	0	0	0	0
Quebec	0	0	0.1	0	0	0	0
Ontario	11.4	10.9	9.3	10.2	7.7	11.2	11.6
Prairies	6.7	14.4	10.6	10.2	11.4	8.9	13.8
B.C.	0.5	0.7	0.7	0.6	0.6	0.5	0.9
Total	**18.6**	**26.0**	**20.7**	**21.0**	**19.7**	**20.6**	**26.3**
Other (incl. partially processed)							
Atlantic	1.2	0.2	0	0.3	0	0	0
Quebec	0.2	0	0	0.1	0	0	0
Ontario	5.3	4.6	4.8	4.5	4.9	4.0	4.9
Prairies	6.1	3.6	2.3	3.9	3.8	1.5	3.0
B.C.	4.0	3.5	3.5	4.1	3.3	2.0	2.8
Total	**16.8**	**11.9**	**10.6**	**12.9**	**12.0**	**7.5**	**10.7**
Total Domestic Receipts							
Atlantic	1.2	0.2	0	0.3	0	0	0
Quebec	3.3	2.6	0.1	0.1	0	0	1.4
Ontario	72.9	75.1	77.1	73.6	73.9	66.2	74.9
Prairies	58.8	65.9	60.6	60.8	58.4	50.9	63.4
B.C.	21.0	24.5	24.6	23.5	23.8	23.7	25.1
Total	**157.2**	**168.3**	**162.4**	**158.3**	**156.1**	**140.8**	**164.8**
B. Crude Oil Imports							
Atlantic	37.6	56.3	54.2	49.7	45.2	42.3	43.8
Quebec	35.7	44.2	47.8	41.9	43.5	39.7	46.1
Ontario	0.4	0.5	0.1	0.4	0.2	0.9	0.2
Prairies	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	0.1	0
Total	**73.7**	**101.0**	**102.1**	**92.0**	**88 .9**	**83.0**	**90.1**
C. Total Receipts							
Atlantic	38.8	56.5	54.2	50.0	45.2	42.3	43.8
Quebec	39.0	46.8	47.9	42.0	43.5	39.7	47.5
Ontario	73.3	75.6	77.2	74.0	74.1	67.1	75.1
Prairies	58.8	65.9	60.6	60.8	58.4	50.9	63.4
B.C.	21.0	24.5	24.6	23.5	23.8	23.8	25.1
Total	**230.9**	**269.3**	**264.5**	**250.3**	**245.1**	**223.8**	**254.9**

Appendix VI
International and Domestic Crude Oil Prices
(US$/bbl)

A.	AT SOURCE		Canadian Par	WTI NYMEX	Brent North Sea
	1991	2Q	19.73	20.77	18.94
		3Q	20.52	21.65	19.90
		4Q	20.63	21.77	20.59
		Ave.	20.40	21.50	20.09
	1992	1Q	17.87	18.92	17.96
		2Q	20.06	21.23	19.98
		Jul.	20.65	21.74	20.33
		Aug.	20.24	21.29	19.79
		Sep.	21.07	21.92	21.21
		3Q	20.65	21.65	20.08

C.	AT CHICAGO		Canadian Par	WTI NYMEX	Brent North Sea
	1991	2Q	21.01	21.37	20.93
		3Q	21.81	22.25	21.90
		4Q	21.92	22.36	22.42
		Ave.	21.69	22.09	22.11
	1992	1Q	18.98	19.52	19.59
		2Q	21.40	21.82	21.58
		Jul.	22.02	22.34	21.89
		Aug.	21.60	21.88	21.47
		Sep.	22.18	22.51	21.87
		3Q	21.93	22.25	21.75

C.	AT MONTREAL		Canadian Par	Brent North Sea
	1991	2Q	21.30	20.59
		3Q	-	21.47
		4Q	-	22.07
		Ave.	-	21.74
	1992	1Q	-	19.38
		2Q	-	21.30
		Jul.	-	21.61
		Aug.	-	21.15
		Sep.	-	21.55
		3Q	-	21.43

Appendix VII
Average Regular Unleaded Gasoline Prices
(Self-Serve)
1991-1992

	---------------- 1991	------------------		---------- 1992	----------
	Sept. 24	**Dec. 31**	**Mar. 31**	**June 30**	**Sep. 29**
	-----------------------cents per litre-----------------------------------				
St John's (NFLD)	61.8	61.8	60.9	60.9	59.9
Charlottetown	60.6	61.1	60.3	60.0	60.4
Halifax *	60.2	59.9	59.0	58.9	58.0
Saint John (N.B.) *	60.0	60.0	56.8	54.5	56.9
Montreal	66.5	63.8	59.0	61.8	59.5
Toronto	57.9	47.7	49.6	58.1	55.3
Winnipeg	53.8	49.8	46.8	53.9	47.9
Regina	42.9	50.9	41.9	43.9	49.9
Calgary	50.5	49.2	42.5	51.6	49.0
Vancouver	49.9	49.6	55.9	56.9	47.7
Average	**57.7**	**53.7**	**52.4**	**57.4**	**54.2**
Consumption taxes include:					
Federal	12.2	11.9	11.8	12.2	12.0
Provincial	13.1	13.1	13.8	14.0	13.9

* *Full-Serve*

Appendix VIII
Consumption Taxes on Petroleum Products
(September 1992)

	Ad valorem		Gasoline			Diesel
	Mogas	Diesel	Reg UL	Mid UL	Prem UL	
	----------%----------		------------------ (cents per litre) -------------			
Federal Taxes						
Estimated GST (7%)			3.5	3.8	4.0	3.3
Excise			8.5	8.5	8.5	4.0
Provincial Taxes						
Newfoundland [a]			13.7	13.7	13.7	15.6
Prince Edward Island	23	26	11.5	11.5	11.5	11.5
Nova Scotia	24.5	31.5	12.3	12.3	12.3	14.0
New Brunswick			10.7	10.7	10.7	13.7
Quebec [b]			18.9	19.2	19.5	18.7
Ontario			14.7	14.7	14.7	14.3
Manitoba			10.5	10.5	10.5	10.9
Saskatchewan			13.0	13.0	13.0	13.0
Alberta			9.0	9.0	9.0	9.0
British Columbia [c]			10.0	10.0	10.0	10.5
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	(d)	9.4	9.4	9.4	8.0

(a) The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay, Labrador.

(b) Reduced by varying amounts in certain remote areas and within 20 kilometres of the provincial and U.S. borders.

(c) Additional transit tax of 3.0 cents per litre in Vancouver.

(d) 85% of gasoline tax.

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional area	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude Oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydro carbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Synthetic crude oil	Crude oil production treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

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L'ÉNERGIE DE NOS RESSOURCES - NOTRE FORCE CRÉATRICE

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Canadian Oil Markets and Emergency Planning Division
Energy Sector
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Appendices

The Canadian Oil Market

This issue of the Canadian Oil Market reviews Canadian oil supply and demand developments in 1992.

Highlights

. A modest improvement in the economy with generally lower refined product prices led to a marginal growth in refined product demand in 1992. The increase in product sales reflected higher motor gasoline and 'other' products consumption.

. In 1992, the drilling utilization rate plummeted to record lows. However, activity grew substantially late in 1992 in the wake of changes to Alberta's royalty regime and federal tax incentives.

. Canada produced significantly more crude oil in 1992. The downward trend in conventional light crude oil production was reversed reflecting steady production in western Canada and the start up in June of the Cohasset/Panuke development off the coast of Nova Scotia. A rise in heavy crude supply reflected increased upgrading capacity in both Canada and the United States.

. The small increase in demand for refined products did not translate into higher crude runs. Refinery throughput continued to decline with about half of the decrease occurring in the Atlantic region where a lengthy turnaround at the Come-by-Chance refinery brought operations to a halt in the fall.

. Crude oil exports continued to grow in 1992 reaching their highest level since the mid-1970's. Most of the increase was due to a sizable rise in production in conjunction with lower refinery demand in Ontario and western Canada.

The Canadian Oil Market

1. Refined Petroleum Product Consumption

. Higher sales of motor gasoline and 'other' refined products accounted for all the growth in product consumption in 1992. Demand for middle distillates and heavy fuel oil remained flat.

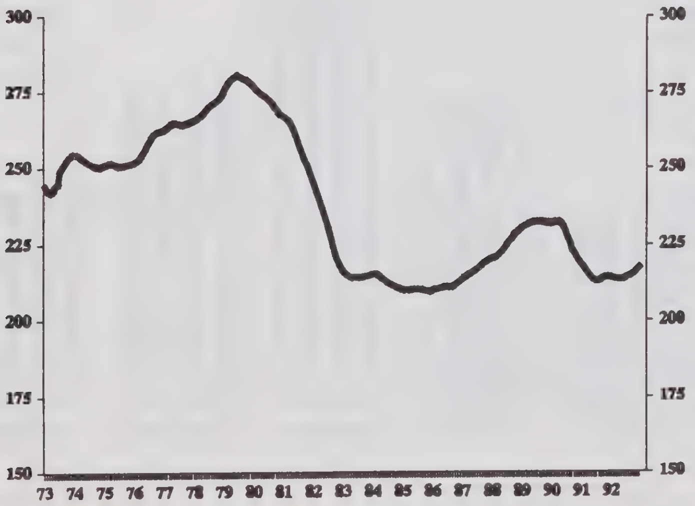
Demand for refined products remained weak in Canada during 1992, rising by slightly less than 1% from the previous year to just 218 000 m^3/d. The increase in product sales such as it was, reflected higher consumption of motor gasoline and 'other' products. Sales of motor gasoline averaged 91 000 m^3/d, marginally higher than in 1991. There was no change in diesel fuel or heating oil demand which remained at 43 000 m^3/d and 18 000 m^3/d, respectively. Heavy fuel oil (HFO) sales also remained steady overall at 22 000 m^3/d. A small drop in HFO demand in British Columbia, reflecting the opening of the Vancouver Island natural gas pipeline in the fall of 1991 was, in effect, offset by higher demand in the Atlantic and Ontario. To help make up for a shortfall in nuclear power generation, Ontario stepped up its use of HFO to generate electricity. Demand for 'other' products rose marginally to 44 000 m^3/d, largely on the strength of higher petrochemical feedstock sales.

The marginal growth in sales in 1992 conformed with a modest improvement in the economy, and with generally lower refined product prices after these had peaked during the Persian Gulf conflict in early 1991. If the economic recovery continues to gather momentum then the modest upturn in refined product sales that got underway in 1992 should persevere in 1993.

As shown in figure 1.1, the most recent peak in refined product sales occurred in 1989. The following year demand plummeted with the onset of the recession and the Persian Gulf conflict. By 1991, demand had fallen by some 20 000 m^3/d, or 9%, to 216 000 m^3/d, with the decline pervasive across all product categories and regions. The recession had negated almost all the growth in refined product consumption that took place between 1985 and 1989, the last period of expanding product demand.

Nevertheless, this most recent downturn in product demand pales in comparison to the previous one, which saw demand fall by 70 000 m^3/d to 213 000 m^3/d between 1980 and 1985. The marked differences in the severity and the duration of the two downturns is largely explained by the fact that, in the earlier downturn, other factors, besides an economic recession,

Figure 1.1
Refined Petroleum Product Sales
000 m^3/d



were depressing demand. For example, oil prices in Canada, even though regulated at below world levels, were comparatively high and rising (vis-a-vis natural gas and electricity prices), in the five years leading up to oil market deregulation in mid-1985.

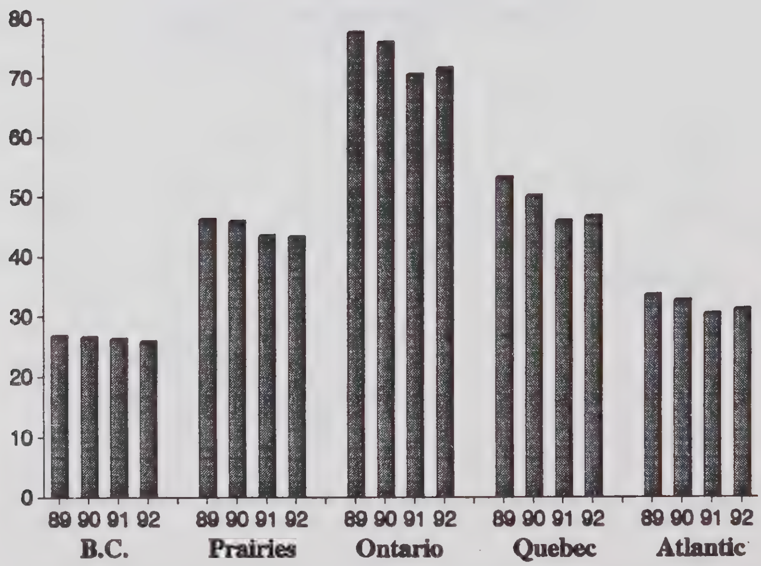
Rising oil prices tend to dampen oil demand in two ways: by directly reducing the consumption of oil-intensive goods and services; and, indirectly, by encouraging end-users to substitute other energy commodities whose prices may not have risen to the same extent. As a case in point, heavy fuel oil, which was particularly vulnerable to fuel switching, steadily lost market share to natural gas and electricity as oil prices climbed during the early 1980's.

Moreover, the steep downward trend in refined product sales in the early 80's was exacerbated by the prevailing view that oil prices would climb indefinitely. The latter spawned a number of government programs, at both the federal and provincial levels, which subsidized improvements in fuel efficiency and conversions from oil to other fuels in both the public and private sectors.

By comparison, the most recent downturn has been mainly a product of the recession. Except during the Persian Gulf conflict when Canadian oil prices spiked to their highest nominal level in history, oil prices have remained relatively low and steady during this recession, both in real terms, and vis-a-vis alternative fuel sources. Given the significant amount of off oil fuel switching in the early 80's, which saw light and heavy fuel oil consumption drop by half and two-thirds respectively, there are now far fewer fuel oil markets left that remain vulnerable to penetration from alternative fuels. For this reason, and because oil prices are forecast to rise only slowly over the long run, any future erosion of oil's consumption base is expected to be a gradual process.

The following figure illustrates regional refined product consumption since 1989.

Figure 1.2
Refined Petroleum Product Sales by Region
000 m^3/d



2. Drilling and Exploration Activity

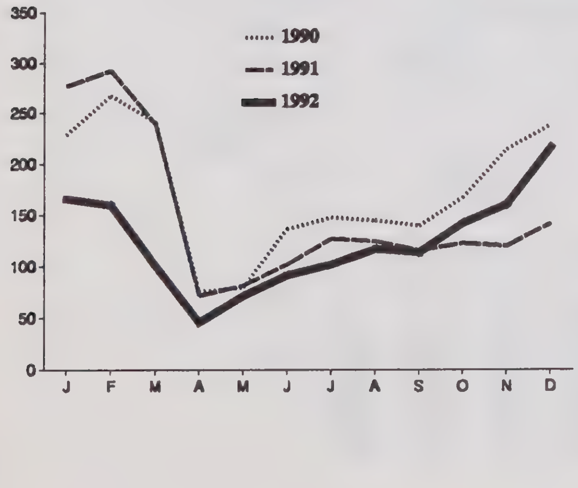
. The drilling industry in western Canada after a dismal 1992 appears poised for a modest upturn on the heels of sweeping royalty changes in Alberta.

The drilling industry in western Canada, due primarily to weak crude oil and natural gas prices, has been on a slide for nearly a decade. 1985 was the last year that the industry reported a rig utilization rate above the 50% mark considered necessary for the industry to break even.

In 1992 the utilization rate plummeted to 28% with only 123 of 437 rigs operating. Despite this dismal performance, the industry appears poised for a modest upturn with much of this optimism based on a jump in fourth quarter activity. Of the 434 available rigs, 173 were reported active, a significant improvement on the 124 of 410 rigs operating a year earlier.

Although it is not uncommon for a winter surge in activity even during a downturn, a number of factors suggest a more prolonged recovery. The revival is attributed primarily to Alberta's October 1992 royalty relief package, combined with a boost in the federal tax write-offs on exploration, stable crude oil and rising natural gas prices, a lower Canadian dollar relative to the U. S. dollar and lower interest rates.

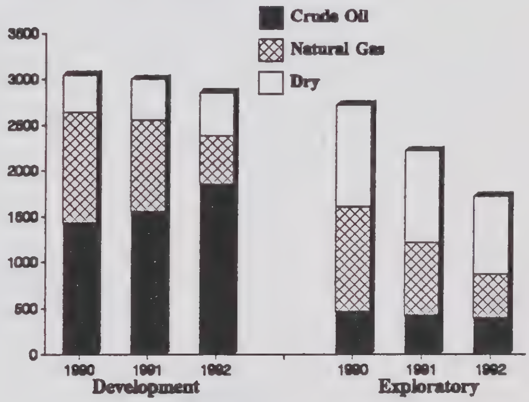
Figure 2.1
Drilling Activity in Western Canada
(Number of Wells)



The Alberta royalty relief package was designed to stimulate drilling activity in that province were the bulk of western Canada drilling takes place. The package included a lower base royalty structure as well as a permanent twelve-month royalty holiday for oil exploration wells, reduced royalties on horizontal re-entry wells and reactivated oil wells, and reduced experimental oil sands royalties.

Only 4 600 wells were drilled in 1992 compared with 5 200 a year earlier. Of this number about 30% proved dry. Exploration drilling took a back seat to development activity. Exploration, representing about 40% of western Canada's total well completions, decreased almost 25% from 1991 with natural gas exploration recording the largest drop.

Figure 2.2
Well Completions in Western Canada
(End-of-year)



The Canadian Association of Oil Drilling Contractors (CAODC), based on indications of a strong first quarter of 1993, expects a 60% rise in the number of active rigs in 1993. Rig utilization is expected to reach 46% with 193 of 414 rigs operating. Total well completions are also expected to increase to about 6 100 wells with 5 100 drilled in Alberta.

Drilling activity could experience a slowdown later in 1993 with the June termination of some provincial incentive programs. Some producers, anticipating the termination of these programs, may have scheduled most of their 1993 drilling in the first half of the year. This is supported somewhat by the CAODC flat forecast for the latter half of the year.

Figure 2.3
Drilling Activity In Western Canada

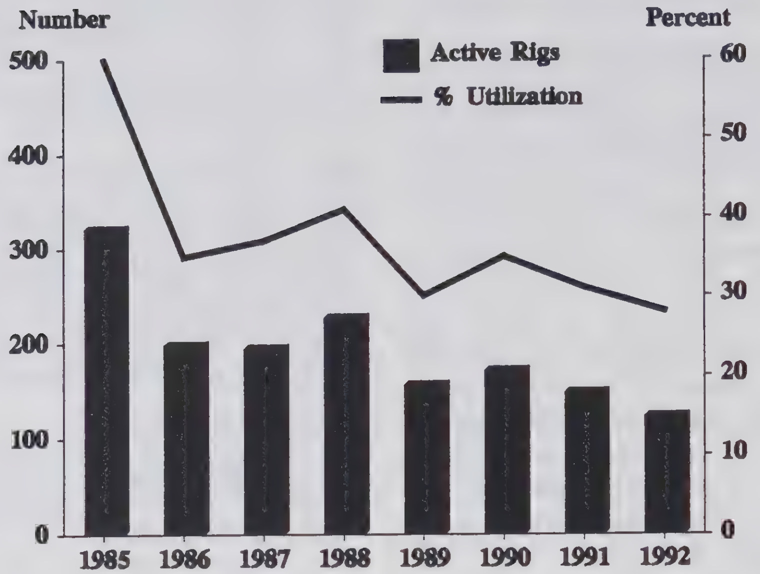
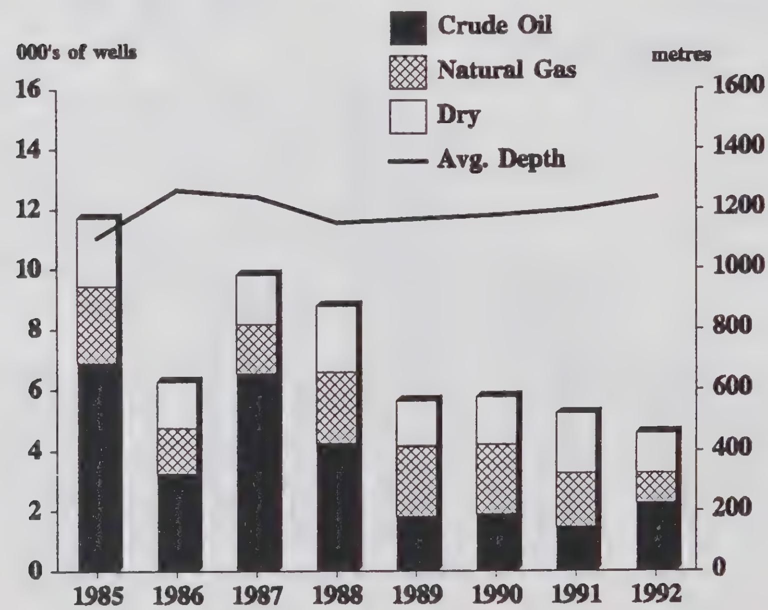


Figure 2.4
Wells Drilled and Average Depth



3. Crude Oil Supply

. Domestic crude oil production jumped 4% in 1992 due to a modest rise in conventional light crude oil production, record synthetic crude output and rising demand for heavy crude oil.

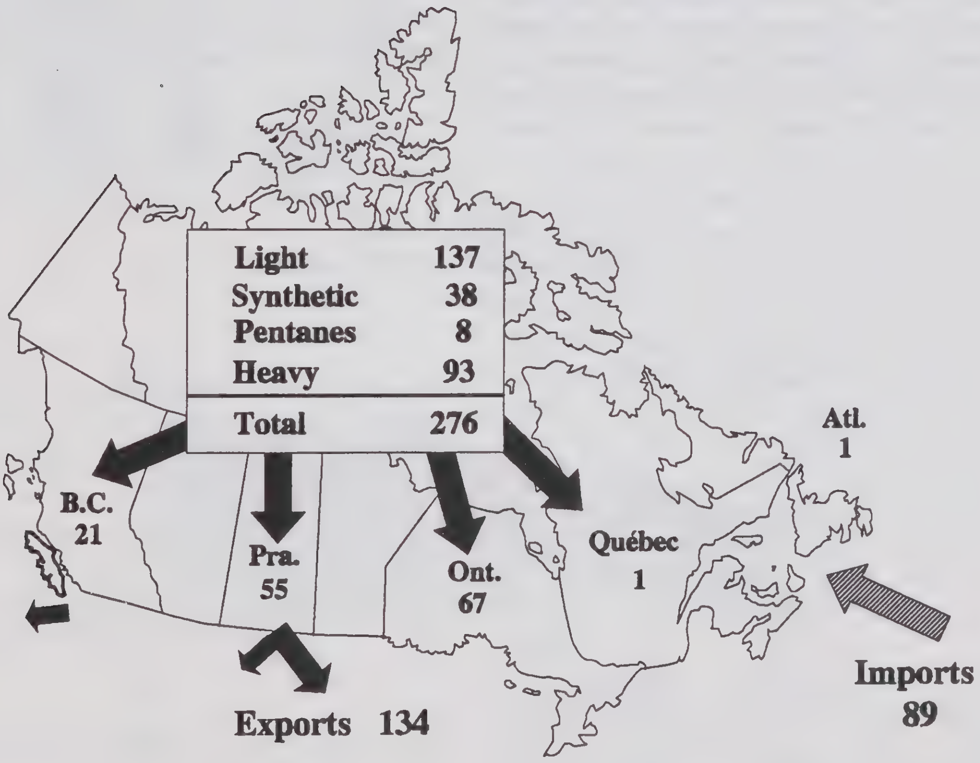
. Crude oil imports declined in 1992 for the first time since deregulation of the Canadian oil market in the mid-80's. The decline in imports mainly reflected a temporary drop in processing activity in the Atlantic region.

3.1 Total Supply

Total crude supply in 1992 averaged 367 000 m^3/d compared with 362 000 m^3/d a year earlier. Of this volume domestic supply (including recycled diluent, production from Bent Horn, Ontario and Nova Scotia, surplus upgrader supply and estimated inventory change) averaged 278 000 m^3/d. Total imports averaged 89 000 m^3/d. Exports were 134 000 m^3/d.

Fourth quarter domestic supply averaged 279 000 m^3/d. Imports averaged 93 000 m^3/d. Exports were 135 000 m^3/d.

Figure 3.1
Supply and Disposition of Crude Oil and Equivalent
(1992)
000 m^3/d



3.2 Domestic Production

Crude oil production in Canada averaged 276 000 m^3/d in 1992. Despite earlier indications of a drop in production from the Western Canadian Sedimentary Basin particularly for conventional light crude, and a decline in reserve replacement, total production was up 4% or 12 000 m^3/d from the year before.

The upturn in crude oil production occurred despite the continuance of a severe slump in western Canadian oil and natural gas drilling. While demand and prices for gas remained weak for most of the year, crude oil prices firmed and remained relatively stable after falling from their peak during the Persian Gulf crisis two years earlier.

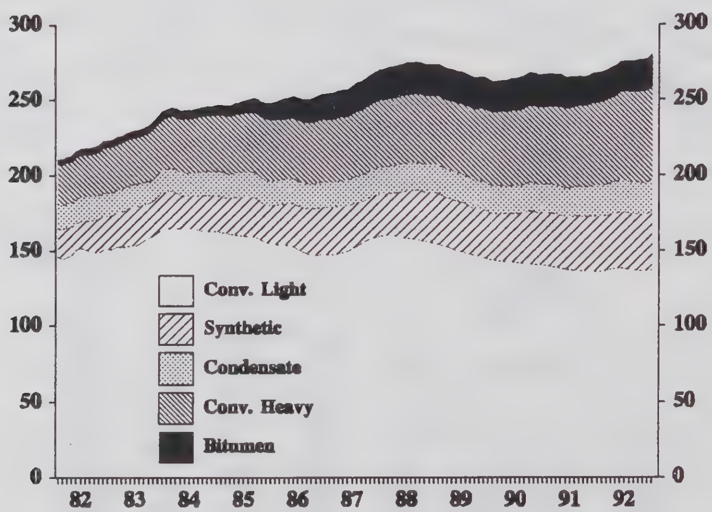
Light Crude Oil and Equivalent Production

Conventional light crude oil production at 137 000 m^3/d was marginally higher than a year earlier. The halt in the downward trend was primarily the result of the June start-up of the Cohasset/Panuke development, Canada's first commercial offshore project, located 250 kilometres off the coast of Nova Scotia, combined with steady production from western Canada. Producers, turning from oil exploration to development projects and utilizing increasingly popular horizontal drilling methods, are reported to have significantly improved the production rates of some of western Canada's older conventional fields.

The supply of light crude oil was further bolstered by record synthetic crude oil production from Alberta's Syncrude and Suncor oil sands plants. Production at 38 000 m^3/d was up 4% or 2 000 m^3/d from the year before. Synthetic crude production represents about 14% of total domestic supply compared with about 10% in 1985. Synthetic crude production is considered essential in offsetting the expected decline in conventional production over the long term.

Pentanes plus (condensate) supply at 21 000 m^3/d, was 2 000 m^3/d or 10% higher than that recorded in 1991. This increase was largely due to a rise in natural gas production of which pentanes plus is a by-product. Production increased late in the year with the start-up of Shell's Caroline gas processing plant in the Alberta foothills. About 60% of pentanes plus production was used as heavy crude diluent.

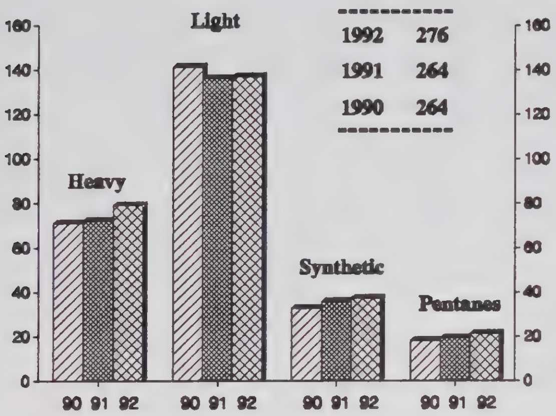
Figure 3.2.1
Historical Crude Oil Production
000 m^3/d



Heavy Crude Oil Production

Heavy (blended) crude oil production experienced a revival in 1992. At almost 93 000 m^3/d production was up 9% or 8 000 m^3/d from the year before. All of the increase was in conventional crude production averaging 59 000 m^3/d with bitumen output remaining relatively unchanged.

Figure 3.2.2
Domestic Crude Oil Production
000 m^3/d



Demand for heavy crude was substantially higher than the year before as a result of increased upgrading capacity at the Conoco refinery in Billings, Montana and the November start-up of the Lloydminster, Biprovincial Upgrader. The plant initially processed about 3 200 m^3/d of synthetic crude from slightly less heavy blended crude feedstock. Production is expected to gradually increase to about 7 000 m^3/d by the end of 1993.

Improved crude oil prices and rising upgrader demand prompted Imperial Oil to announce plans to bring on stream two mothballed phases of its Cold Lake bitumen project by mid-1993. It is estimated that this will increase bitumen production by an additional 3 000 m^3/d by the end of 1993.

Other companies, citing improved markets for heavy crude as well as the impact of new technology on production, are reported to be bringing back on stream a number of heavy crude oil projects. Many of these projects, located in northeastern Alberta, were put on hold by poor prices during the 1980's.

3.3 Crude Oil Imports

Following deregulation of the Canadian oil market in mid-1985, imports of crude oil began to climb, reversing a downward trend that had begun after the first oil crisis of 1973. The use of foreign crudes rose steadily from 1985 until 1992, at which point there was a slight decline. Some of the growth in imports in recent years reflected the impact of deregulation itself. Atlantic refiners stopped using Canadian crude almost immediately since deregulation entailed the elimination of transportation subsidies. In Quebec, those refiners having the benefit of pipeline access to western Canadian oil production through IPL's Sarnia-Montreal extension, increased their use of offshore crudes only as these became progressively cheaper relative to Canadian crudes.

Two other factors have also caused oil imports to rise in recent years. Following the national trend, demand for refined products rose steadily in eastern Canada from 1985 until the onset of the recession more than two years ago. More importantly, some Atlantic refiners entered into processing agreements which involved refining foreign crudes mainly for refined product markets in the New England states. In fact, the 16 000 m^3/d Come-by-Chance refinery in Newfoundland, which was reopened in 1987, delivers virtually all its products to the export market. Processing agreements have therefore implied a commensurate increase in refined product exports from the Atlantic region.

The importance of processing agreements in maintaining a high rate of refinery utilization in the Atlantic region is bound to grow in 1993. A small Dartmouth, Nova Scotia refinery will no longer supply the local market but instead will refine about 3 000 m^3/d of Norwegian crude for the export market. The reduction in refined products supply in the Atlantic market entailed in this latest agreement will be offset by product transfers from a sister refinery in Quebec.

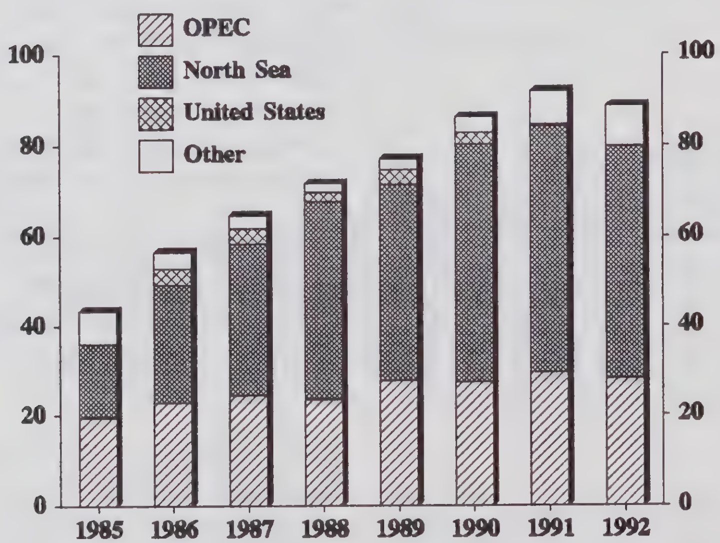
The 3 000 m^3/d decline in total imports to 89 000 m^3/d in 1992 mainly reflects a drop in processing activity in the Atlantic region. Atlantic imports dropped by 5 000 m^3/d to 44 000 m^3/d. Much of this drop can be attributed to a prolonged turnaround at the Come-by-Chance refinery which lasted from early August to mid-October. Imports into the Atlantic were also reduced by about 2 000 m^3/d during the fourth quarter when the region's refiners started using some of the Scotian light crude from the Panuke oil project off the coast of Nova Scotia which commenced production in June .

Imports actually increased in Quebec by about 2 000 m^3/d to 44 000 m^3/d. Quebec was now importing almost as much crude as the Atlantic. The increase made up for the fact that western Canadian crude was no longer being delivered to Montreal through the Sarnia-Montreal extension which was shut down in mid-1991. Although the line was reactivated last July, the linefill operation has fallen far behind schedule. Because of this delay, deliveries of western Canadian crude oil to Montreal are not expected to resume before the second quarter of 1993.

In Ontario, the closure of the Sarnia-Montreal extension has had just the opposite effect on the level of imports. Ontario refiners appear to have taken advantage of the surfeit of domestic supply arising from the removal of the Montreal market. Since the closure of the extension, Ontario imports, almost entirely from the United States, have consistently averaged below the 1 000 m^3/d range.

North Sea crudes comprised 58% of total imports in 1992, almost two-thirds of which were delivered to Quebec refiners. OPEC supplied slightly less than a third of the total, most of which went to the Atlantic region. Saudi Arabia and Nigeria have consistently been the principle sources of OPEC crude. Imports of Mexican heavy crude rose substantially in 1992 to compensate for the fact that western Canadian heavy crude oil was no longer available in Montreal to make asphalt.

Figure 3.3
Crude Oil Imports
000 m^3/d



4. Crude Oil Disposition

. Despite a marginal increase in refined product demand in Canada, refiners continued to reduce their demand for crude oil in 1992. The decline largely reflected reduced net exports of refined products.

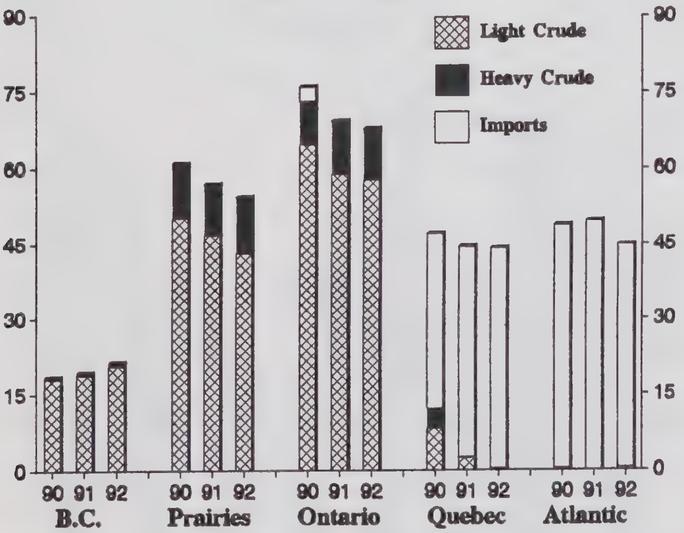
4.1 Canadian Refinery Crude Oil Receipts

The small increase in the demand for refined products in 1992 did not translate into increased deliveries of crude oil to Canadian refineries. On the contrary, refinery crude oil receipts continued to fall, albeit at a slower rate. Crude oil demand declined from 1991 by almost 7 000 m^3/d to 233 000 m^3/d. Relative to 1990, the most recent peak year in refinery demand, receipts were down by some 18 000 m^3/d. Except for British Columbia, all regions have shared in the decline. In the case of British Columbia, crude oil demand has been bolstered by the need to compensate for reduced transfers of semi-refined products from Edmonton refineries to sister refineries in Vancouver; and by a rise in net exports of refined products from the region.

At the national level, the decline in crude oil receipts in 1992 reflected both a 1 000 m^3/d drawdown of crude oil inventories over the year, and reduced sales of refined products in the export market after these had reached a record level in 1991. More than two-thirds of the decline occurred in the Atlantic where there was a decline in refining for the export market. This, in turn, lowered the level of crude oil imports in 1992.

Except for a few shipments of Bent Horn and Scotian crudes in the latter half of the year, Quebec and Atlantic refiners relied on foreign feedstocks. On the other hand, refiners west of Quebec processed domestic crude oil almost exclusively. The demand for domestic light crude oil dropped by 4 000 m^3/d to 123 000 m^3/d, in part because no western Canadian light crude was delivered to Montreal over the entire year, and in part because refined product markets were depressed, particularly in Ontario. All of the decline occurred in conventional light crude receipts, there being small increases in the use of both synthetic light crude and condensate.

Figure 4.1
Refinery Crude Oil Receipts
000 m^3/d



Receipts of domestic heavy crude oil (conventional and bitumen) rose marginally to almost 22 000 m^3/d. About a third of this demand came from the Newgrade upgrader which managed to operate without encountering any major problems in 1992. Receipts of bitumen remained limited to about 2 000 m^3/d, tantamount to about 10% of Canada's bitumen production.

4.2 Crude Oil Exports

Sluggish domestic demand for indigenous crude oil combined with falling production and rising demand in the United States helped to push Canadian crude oil exports up to their highest level in two decades. In 1992, about 50% of Canada's crude oil supply found its way to the export market compared with 30% in 1985.

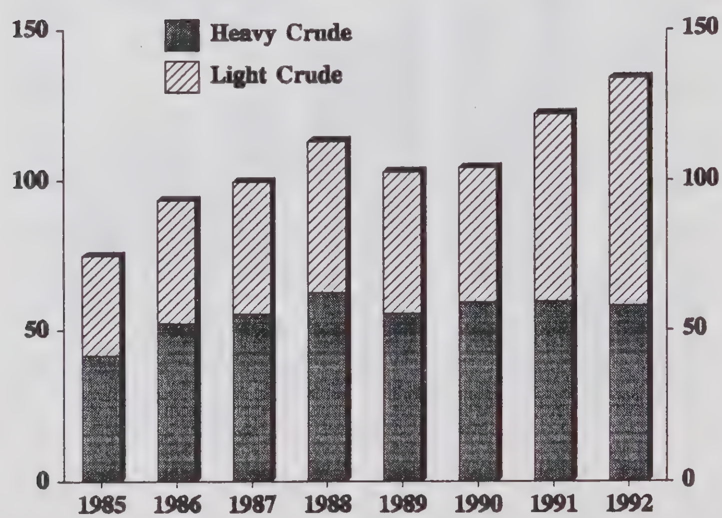
Averaging 134 000 m^3/d, total crude oil exports in 1992 were up about 10% or 12 000 m^3/d from the year before. All of the increase was the result of a 20% or 13 000 m^3/d jump in light crude oil exports to 76 000 m^3/d. Blended heavy crude was down marginally to 58 000 m^3/d. Fourth quarter exports averaged 135 000 m^3/d compared with 123 000 m^3/d a year earlier.

The volume of light crude oil exports may have been inflated by the blending of light crude with heavy crude oil at the feeder line stage prior to entering major trunk lines for delivery to refineries. By year-end, about 8 000 to 10 000 m^3/d of heavy crude is estimated to have been blended with light crude streams. Conversely, the volume of heavy crude exports may have been deflated commensurately.

Most Canadian crude oil exports were delivered to the United States with about 85% of this volume delivered by pipeline to the U.S. Great Lakes region. Canadian crude oil exports, according to the EIA (U.S. Energy Information Administration), accounted for about 13% of all U.S. imports in 1992, the highest since 1979.

EIA data indicates that production from domestic U.S. oilfields averaged 1.1 million m^3/d in 1992, down 4% from 1991, and reached the lowest level since 1960. A 5% rise in deliveries of foreign crude oil offset this decline in domestic production. Canada is the third largest supplier of foreign crude oil to the United States following Saudi Arabia and Venezuela.

Figure 4.2
Crude Oil Exports
000 m^3/d



4.3 Canada's Oil Trade Balance

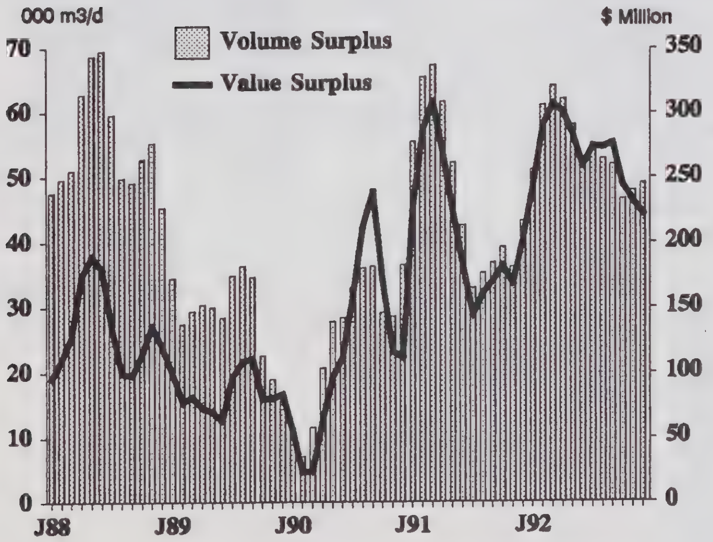
Canada's oil trade surplus reached a record level of \$3.2 billion in 1992, reflecting relatively high net exports of both crude oil and refined products. Figure 4.3.1 shows the value and volumetric trends in the oil trade surplus over the past five years. As indicated in the figure, oil contributed almost \$275 million per month to Canada's merchandise trade balance in 1992. By comparison, from early 1989 through to mid-1990, oil's contribution generally fell well below \$100 million per month.

The immediate cause of the reversal of trend in the latter half of 1990 was the rapid, albeit short-lived, rise in crude oil prices during the Persian Gulf conflict. Canada, as a net oil exporter gained more than it lost from the increase in oil prices. This is suggested in the figure by the greater escalation in the value of the surplus vis-a-vis the volumetric surplus during the fall of 1990.

Despite oil prices having subsequently fallen back to pre-conflict levels by early 1991, the value to volume ratio of net exports has remained quite high in comparison to the two years leading up to the conflict. This is because Canada's net exports now consist of proportionately more higher-valued light crude oil and refined products than before.

Trends in Canada's volumetric oil trade surplus are closely tied to developments in the domestic oil sector. Figure 4.3.2 shows Canada's trade surplus in crude oil and refined products as the difference between crude oil production and refined product consumption. It should be noted that the trend in net oil exports in figure 4.3.2 only approximates that of figure 4.3.1. Figure 4.3.1 is based on Canada Customs data while figure 4.3.2 is based on data gathered by the Industry Division of Statistics Canada. Often divergences occur because of differences in the classification and timing of the reported data between the two agencies. They also occur because no account is taken of changes in oil inventories in figure 4.3.2.

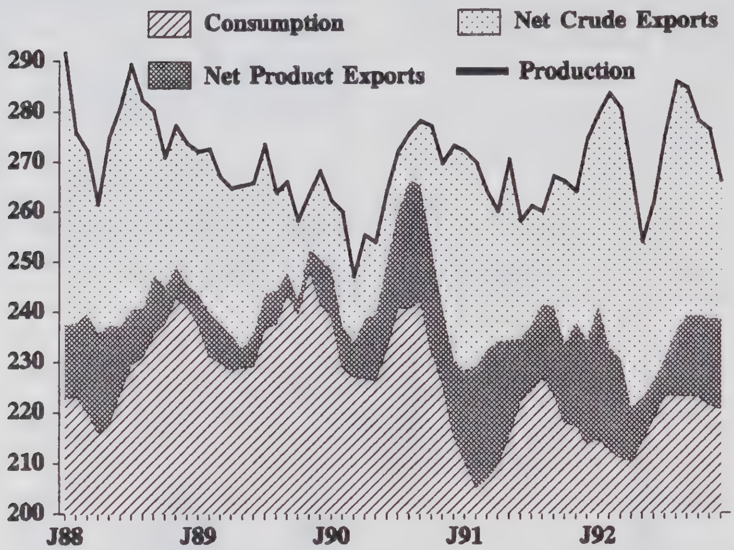
Figure 4.3.1
Canada's Oil Trade Surplus
000 m^3/d



As shown in figure 4.3.2, the surplus steadily narrowed during 1988 and 1989 as a result of falling production and rising consumption. The turnaround occurred when high oil prices during the Persian Gulf conflict bolstered production while dampening demand for refined products. At the same time, the recession also began exerting strong downward pressure on product demand. Product sales plummeted in the fourth quarter of 1990 and have remained in a slump ever since.

Rising crude production has been the other factor sustaining the recovery in net exports during 1991 and 1992. As figure 4.3.2 illustrates, net exports of both crude oil and refined products have risen substantially in the last two years, in part, because of higher crude production; and, in part, because domestic refiners have curtailed their demand for crude oil while increasing product exports to help offset the drop in domestic sales.

Figure 4.3.2
Oil Production, Consumption and Net Trade



5. Pipeline Deliveries

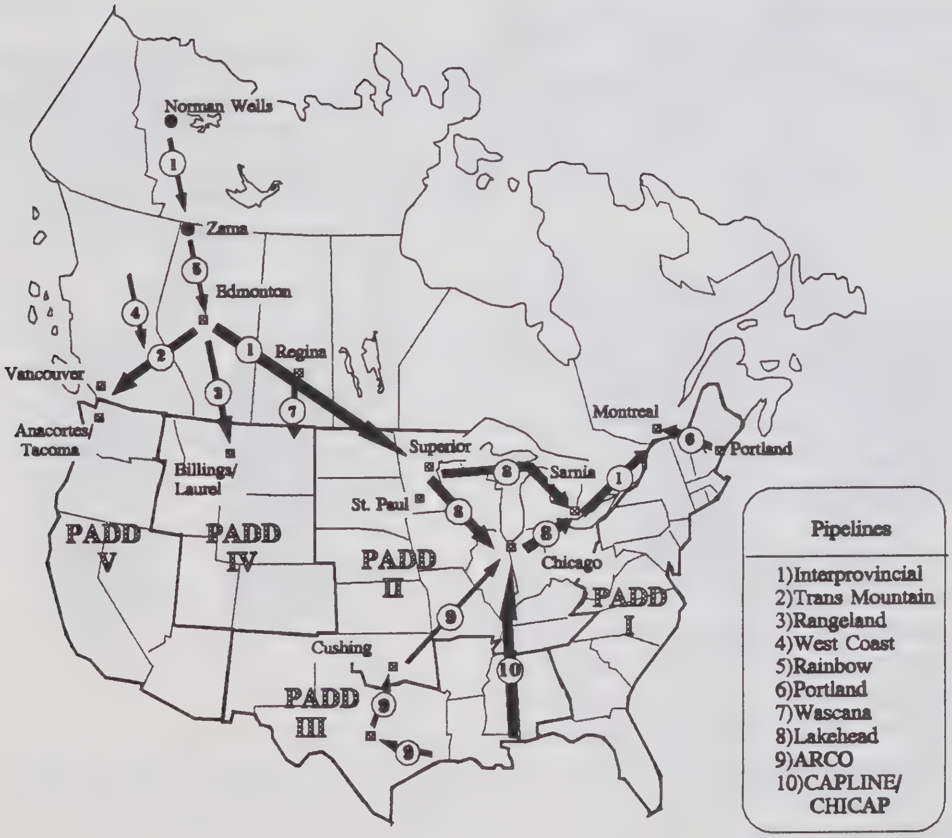
. Pipelines have been subject to a high level of apportionment for the last several years at high cost to industry. In response to apportionment and rising throughput forecasts the industry is considering a number of options including expansion options.

Most Canadian crude oil is gathered at Edmonton, Alberta. It is then delivered to the domestic and export market, for the most part, by a network of pipelines.

The bulk of Canadian crude oil exports are delivered east into the United States via the Interprovincial and Lakehead pipeline systems. Smaller volumes are delivered by the Trans Mountain to the west coast for delivery to large U.S. refineries in the Puget Sound area and for tankering offshore. The Rangeland pipeline carries crude oil south into Montana.

Canadian crude oil delivered to the U.S. midwest competes in the key Chicago refining area with U.S. domestic crudes and other foreign crudes delivered through the CAPLINE/CHICAP pipeline system from the Louisiana Gulf Coast and alternatively the ARCO pipeline system from the Texas Gulf Coast via Cushing, Oklahoma.

Figure 5
Major Crude Oil Pipelines



5.1 Trans Mountain Pipe Line Deliveries

The Trans Mountain Pipe Line (TMPL) originates at Edmonton and delivers crude oil, semi refined and refined products some 1 250 kilometres west to the Vancouver area. At Sumas, on the Canada/USA boundary, a subsidiary pipeline extends south another 112 kilometres to supply refineries in north west Washington State at Ferndale, Cherry Point and Anacortes. The pipeline also receives crude from northern British Columbia at Kamloops delivered via the West Coast Pipe Line.

In 1992, TMPL delivered 32 000 m^3/d of crude oil and product compared with 29 000 m^3/d in 1991. Domestic deliveries averaged 26 000 m^3/d of which 23 000 m^3/d (90% crude oil) was delivered to refineries in the Vancouver/Burnaby area. The remainder, composed of refined products, was delivered to Kamloops, British Columbia. Total fourth quarter 1992 deliveries averaged 35 000 m^3/d.

Export deliveries totalled 7 000 m^3/d, up almost 2 000 m^3/d from a year earlier. Of this volume, 3 000 m^3/d was delivered to refiners in the Puget Sound area of Washington State. About 4 000 m^3/d was loaded onto outbound tankers at TMPL's Westridge Marine Terminal on the inner harbour of the Port of Vancouver.

The composition of TMPL throughput changed in 1992 with total light crude moved representing about 82% of deliveries compared with 66% in 1991 while semi-refined and refined products decreased from 22% to 16%. Most significantly, heavy crude deliveries, which prompted an expansion in 1988-1989, declined from 12% to 2% of total throughput.

The decline in heavy crude deliveries was the result of of the opening of the Lloydminster, Bi-provincial Upgrader and expanded upgrading capacity in Billings, Montana. However, an increase in light crude deliveries to Washington State and other offshore destinations via the Westridge Marine Terminal offset the decline in heavy crude throughput.

Figure 5.1.1
Deliveries by Destination
000 m^3/d

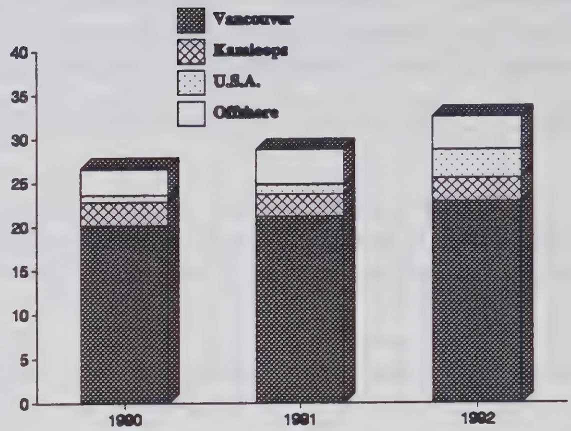
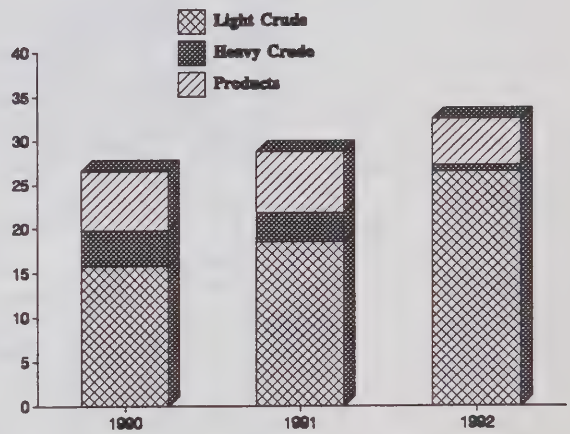


Figure 5.1.2
Deliveries by Type
000 m^3/d



5.2 Interprovincial Pipe Line Deliveries

The Interprovincial Pipe Line (IPL) system consists of three major sections stretching some 3 700 kilometres from western Canada east to Montreal, Quebec. The western section of IPL originates at Edmonton and travels east through Regina, Saskatchewan and crosses the border into the United States near Gretna, Manitoba. The Lakehead portion of the system serves the U.S. Great Lakes region via routes to the north and south of Lake Michigan before they join at Sarnia, Ontario.

The Sarnia to Montreal section of the IPL, closed since mid-1991 due to increased competiveness of offshore crudes in Montreal, was reactivated in July 1992 following an earlier announcement by the Alberta Petroleum Marketing Commission, which markets royalty crude for Alberta, of its intention to resume deliveries of conventional light crude to refineries in Montreal. Line fill operations (365 000 m^3) began in July with crude oil not expected to reach Montreal before April/May 1993.

Despite the closure of the Sarnia-Montreal pipeline, total IPL deliveries in 1992 averaged 231 000 m^3/d compared with 224 000 m^3/d the year before. U.S. destinations received all of the incremental volume with deliveries up almost 8 000 m^3/d to 117 000 m^3/d. Total fourth quarter 1992 deliveries averaged 231 000 m^3/d.

Deliveries to domestic markets decreased as a result of the termination of deliveries to Montreal refineries which averaged about 2 000 m^3/d in 1991. Deliveries to the Prairies and Ontario were up marginally to 32 000 m^3/d and 82 000 m^3/d, respectively.

Figure 5.2.1
Deliveries by Destination
000 m^3/d

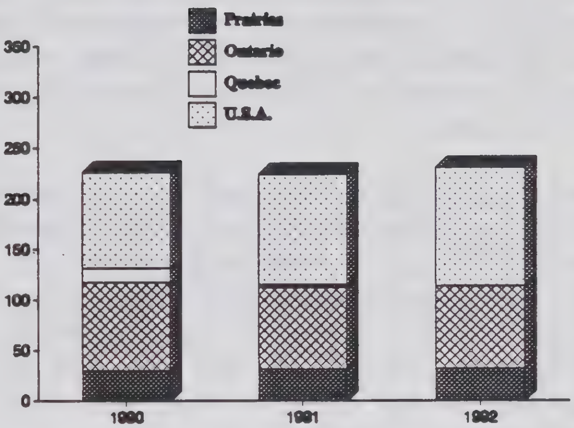
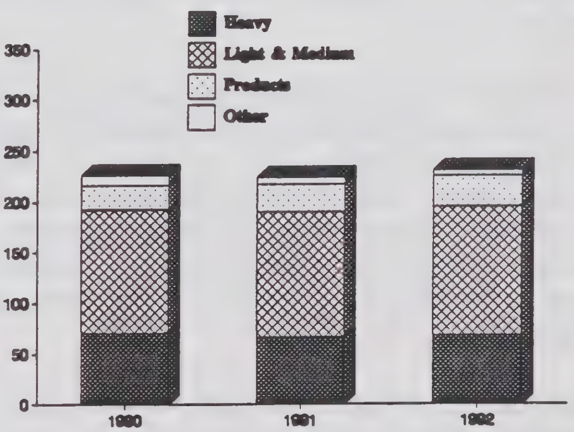


Figure 5.2.2
Deliveries by Type
000 m^3/d



Note: The Sarnia-Montreal pipeline extension was built at a cost of about $250-million in 1976, during a period of considerable instability in world oil markets characterized by a period of high and volatile prices. The government of the day sought to insulate the Canadian economy from the unpredictable international oil market. One policy was to regulate oil prices in Canada at levels below prevailing world oil prices. Oil prices were roughly equalized across Canada by imposing duties on crude oil exports and subsidizing imports. Another policy was to reduce Canada's dependence on crude oil imports by extending the IPL as far as Montreal. Prior to the construction of the line refiners in the Atlantic region and Montreal were virtually dependent upon foreign supplies for crude oil feedstock. The extension also provided an additional market for western Canadian crude oil at a time when the government began limiting light crude oil exports.

5.3 Pipeline Apportionment

Over the past several years there has been a significant rise in demand for space on Canada's major pipelines resulting in apportionment. Apportionment is not a new problem, having existed on the Trans Mountain and IPL systems, as well as other Canadian pipelines over the years.

Most notably, demand for space has exceeded IPL's capacity to deliver in every month except for one since October 1990. It is important to note that not only was IPL operating at a somewhat reduced capacity for most of this period, as a result of major inspection and maintenance programs, but that there was also a significant increase in shippers' nominations driven by excess supply of domestic crude.

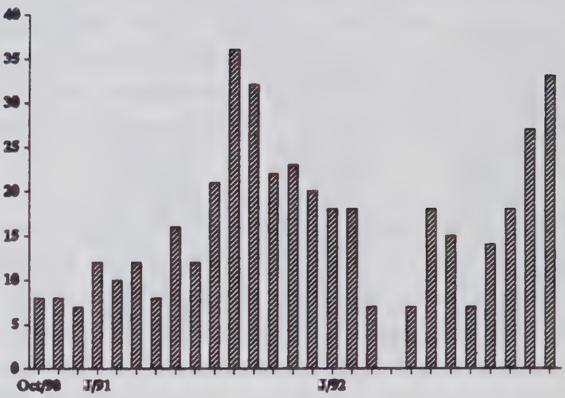
Higher than expected production from western Canada reflects the development of smaller conventional oil fields stemming in part from Alberta's drilling incentive program. Production has been further bolstered by horizontal drilling and other enhanced recovery techniques as well as increased bitumen demand. Rising production coupled with pipeline capacity constraints has resulted in some crude oil price discounting and shut-in, all at a high cost to the industry.

It became evident as apportionment levels grew during 1991 that part of the problem stemmed from shippers inflating their nominations in an attempt to reserve pipeline space. After a number of attempts since 1985 to develop a satisfactory nomination procedure, an industry working committee proposed an alternative procedure which was accepted by IPL and implemented in March 1992.

The committee developed procedures which focused on identifing shippers who inflated their nominations. These offending shippers would then be penalized by restricting their access to pipeline space in the following month.

These March 1992 procedures appear to have been only partially effective as suggested by the following figure.

Figure 5.3.1
IPL Apportionment
(percent)



5.4 Pipeline Expansion Programs

In response to continued apportionment and rising throughput forecasts, both Trans Mountain and IPL are currently evaluating a number of options for pipeline expansion. As well as improving current pipeline utilization by asking producers and shippers to segregate sweet and sour crudes in the gathering system upstream of Edmonton (by end-1993), Trans Mountain is considering a \$22.5 million facilities expansion program involving among other things the installation of new and increased pumping capacity at existing stations. This expansion program is expected to result in a substantial capacity gain of about 7 000 m^3/d.

IPL is considering three options for expanding pipeline capacity. The first option involves a \$150 to \$180 million program to boost capacity by about 8 000 m^3/d with some pipeline looping and the addition of pumping stations. IPL expects this program to be combined with a number of small, cost effective programs to adjust the pipeline system to match changing receipt and delivery patterns.

The second option which is considered most feasible by IPL involves putting a currently inactive line between Regina, and Cromer back into service and constructing an extension between Edmonton and Regina. This configuration, totalling 1 200 kilometres of pipe, is expected to handle only refined products. According to IPL, this option would increase capacity by about 18 000 m^3/d at an estimated cost of $275 million.

Option three is IPL's former Phase 4 expansion proposal introduced in 1988 which involves the construction of a new line utilizing all available and inactive pipe between Hardisty, Alberta and Clearbrook, Minnesota. Light crude oil would move from Edmonton to Hardisty where it would be transferred to tankage. It would then move through the new line to Clearbrook before being transferred to tankage and IPL's lines 2 an 3 for pumping to Superior. The program would also include a new pipeline from Superior to Chicago. IPL expects this option would increase system capacity by as much as 32 000 m^3/d at an estimated cost of nearly a $1 billion.

While exploring expansion opportunities, the pipeline industry is attempting to maximize throughput by scheduling maintenance and inspection programs to coincide with periods of lower throughput such as refinery turnarounds.

6. Refinery Throughput and Utilization

. The national refinery utilization rate averaged 80% during 1992. This was virtually unchanged from the previous year, reflecting the fact that while throughput declined so did refining capacity.

Refinery throughput will normally diverge from refinery crude oil receipts for two reasons. First, feedstocks other than crude oil are also charged in the refining process. Some of the 'other' feedstocks include gas plant butanes (used mostly by Prairie refineries) and partially processed oil (used mostly by refineries in British Columbia). During 1992, these 'other' receipts averaged almost 11 000 m^3/d, accounting for about 4% of total refinery feedstock receipts in Canada. Second, refinery throughput reflects changes in feedstock inventories. Other things being equal, an inventory drawdown will cause refinery throughput to exceed receipts - and vice versa in the case of an inventory build. Over 1992, crude oil inventories at the national level were drawn down at a rate of more than 1 000 m^3/d.

Total throughput averaged 245 000 m^3/d in 1992, almost 7 000 m^3/d below the previous year. About half the decline occurred in the Atlantic region, largely reflecting a lengthy turnaround at the Come-by-Chance refinery which brought its operations to a halt from early August to mid-October.

Petro-Canada closed its small Taylor, B.C. refinery in 1991, reducing Canadian refinery capacity by almost 3 000 m^3/d. This was the first refinery closure in Canada since 1985. Canadian refining capacity subsequently dropped by another 4 500 m^3/d when the Turbo refinery in Alberta was closed permanently in May of 1992. With Canadian refining capacity now estimated to have fallen to about 307 000 m^3/d, the level of throughput in 1992 meant a national refinery utilization rate of almost 80%, virtually unchanged from the previous year. Regionally, the utilization rate was highest in British Columbia where it approached nameplate capacity, and lowest in the Atlantic and Ontario where it fell to 75%.

Figure 6.1 illustrates refinery throughput and capacity in Canada from 1979 to 1992. In 1979, Canada's refining capacity stood at a little over 370 000 m^3/d. By 1992, it had fallen by almost 65 000 m^3/d. A sharp decline in refined product demand in the early eighties led to a series of refinery closures and downsizings (primarily in eastern Canada) during this period. The drop in capacity was however partially offset by the 1984 start-up of Shell's synthetic crude refinery in Scotford, Alberta; and the reactivation of Newfoundland's Come-by-Chance refinery in 1987 after an 11 year hiatus. Figure 6.2 shows refinery utilization rates by region over the same period.

The recent decline in refining capacity should continue with the announced closures of two small refineries in the Vancouver area by mid-1993. The closures will reduce refining capacity in British Columbia by some 8 000 m^3/d. The two refineries will be converted to product finishing and terminalling facilities, receiving refined products via the Trans Mountain Pipe Line from their larger sister refineries in Edmonton. Concomitantly, Trans Mountain is increasing its capacity to deliver refined products to Vancouver in order to accommodate the refinery rationalizations.

The following table "Refining Capacity in Canada" is provided by the *Petroleum Technology Division* of Energy, Mines and Resources.

For further information concerning this table please contact (613) 992-2916.

Figure 6.1
Refinery Utilization vs Capacity in Canada
000 m³/d

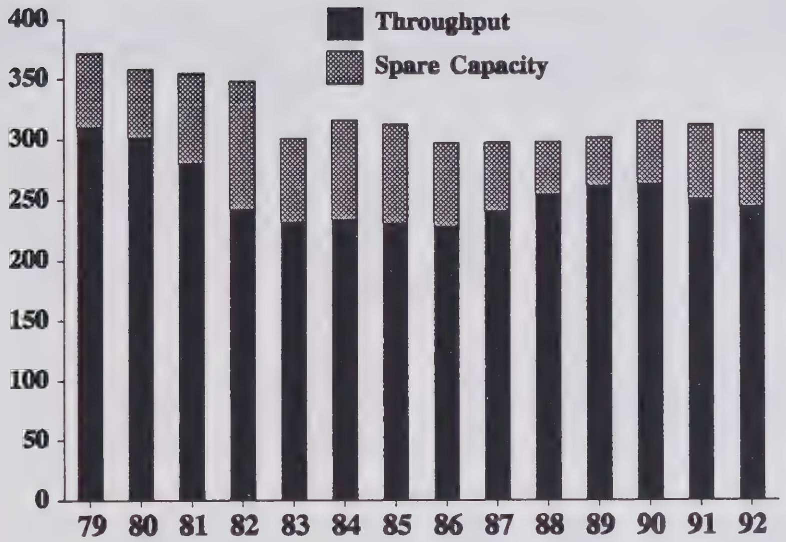


Figure 6.2
Regional Refinery Utilization Rates
(Percent)

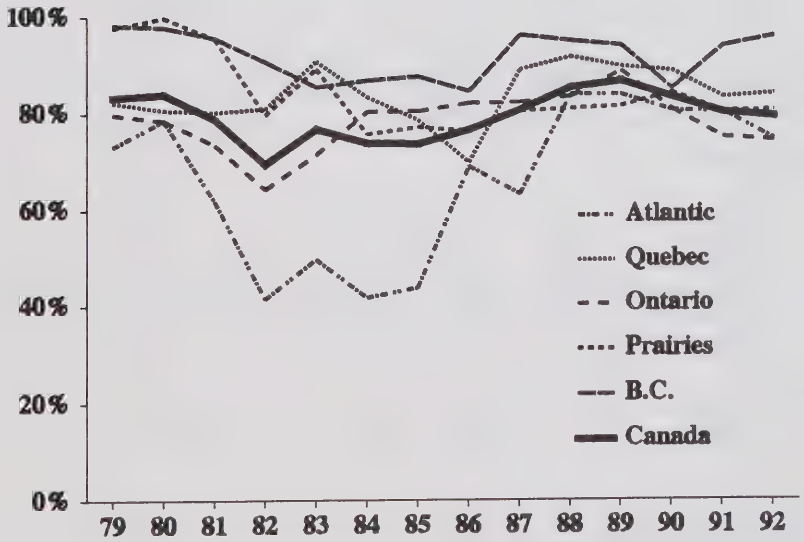


Table 6 **REFINING CAPACITY IN CANADA (as of December 1992)**

Process unit capacities in m³/d

COMPANY	CITY	PROVINCE	CRUDE	VACUUM	VISBREAKER	COKER	FCCU	HCU	RESID UPGRADER	NAPHTHA HTU
ATLANTIC REGION										
NFLD REFINING	Come-By-Chance	NFLD	16700	8900	0	0	0	5560	0	4100
ESSO PETROLEUM	Dartmouth	NS	13100	6360	0	0	3970	0	0	1510
ULTRAMAR	Halifax	NS	3180	1370	0	0	1140	0	0	570
IRVING OIL	Saint John	NB	27700	9810	2860	0	2720	4720	0	7220
			60680	**26440**	**2860**	**0**	**7830**	**10280**	**0**	**13400**
QUEBEC REGION										
PETRO-CANADA	Montreal	QUE	14300	6470	2000	0	2730	2290	790	4230
SHELL CANADA	Montreal	QUE	19070	7850	1910	0	4000	1860	0	5430
ULTRAMAR	St Romuald	QUE	19800	8740	0	0	5500	0	0	3710
			53170	**23060**	**3910**	**0**	**12230**	**4150**	**790**	**13370**
ONTARIO REGION										
ESSO PETROLEUM	Nanticoke	ONT	16900	4930	0	0	6360	0	0	4080
ESSO PETROLEUM	Sarnia	ONT	19310	4530	0	3340	3970	1650	0	5130
PETRO-CANADA	Clarkson	ONT	9530	5460	0	0	0	0	0	1640
PETRO-CANADA	Oakville	ONT	12800	6520	0	0	4040	0	0	3100
POLYSAR	Sarnia	ONT	17000	6360	0	0	0	0	0	0
SHELL CANADA	Sarnia	ONT	11280	3920	640	0	2290	1070	0	2380
SUNCOR	Sarnia	ONT	11200	2600	1000	0	2540	3180	0	4070
			98020	**34320**	**1640**	**3340**	**19200**	**5900**	**0**	**20400**
PRAIRIE REGION										
CO-OP/NEWGRADE	Regina	SASK	7180	3650	0	1320	3000	0	4300	2150
SASK ASPHALT	Moose Jaw	SASK	2110	1160	0	0	0	0	0	0
ESSO PETROLEUM	Edmonton	ALTA	26200	11830	0	0	8400	0	0	9130
PETRO-CANADA	Edmonton	ALTA	19310	4290	0	1130	6360	3000	0	1500
HUSKY	Lloydminster	ALTA	3650	1870	0	0	0	0	0	0
PARKLAND	Bowden	ALTA	950	0	0	0	0	0	0	480
SHELL CANADA	Scotford	ALTA	10872	0	0	0	0	6150	0	3600
~~TURBO RESOURCES~~	~~Balzac (2)~~	~~ALTA~~	~~4640~~	~~1210~~	~~0~~	~~0~~	~~1840~~	~~0~~	~~0~~	~~1650~~
ESSO PETROLEUM	Norman Wells	NWT	510	0	0	0	0	0	0	0
			70782	**22800**	**0**	**2450**	**17760**	**9150**	**4300**	**16860**
BRITISH COLUMBIA REGION										
CHEVRON	Burnaby	BC	7150	1490	0	0	1700	0	0	1590
ESSO PETROLEUM	Vancouver	BC	7200	3800	0	0	1950	0	0	1110
PETRO-CANADA	Port Moody	BC	3970	3480	0	0	0	0	0	2450
~~PETRO-CANADA~~	~~Taylor (1)~~	~~BC~~	~~2860~~	~~250~~	~~0~~	~~0~~	~~1000~~	~~0~~	~~0~~	~~640~~
HUSKY	Prince George	BC	1530	640	0	0	460	0	0	200
SHELL CANADA	Burnaby	BC	3810	1110	0	0	890	0	0	860
			23660	**10520**	**0**	**0**	**5000**	**0**	**0**	**6210**
TOTAL CANADIAN CAPACITY			**306312**	**117140**	**8410**	**5790**	**62020**	**29480**	**5090**	**70240**

(1) Petro-Canada (Taylor) closed mid-1991.
(2) Turbo Resources (Balzac) closed May, 1992.

Table 6 (continued)

REFORMER LOW PRESSURE	REFORMER CONVENTIONAL PRESSURE	DIST HTU	OTHER HTU	ALKYLATION HF	ALKYLATION H2SO4	POLY	ISOMERIZATION C4	ISOMERIZATION C5C6	AROM EXTRACTION	LUBES	ASPHALT
0	4100	4000	0	0	0	0	0	0	0	0	0
1510	0	4080	1430	0	0	410	0	0	0	0	790
0	570	830	0	0	0	0	0	0	0	0	0
0	5510	6440	0	0	954	270	0	1510	0	0	1860
1510	**10180**	**15350**	**1430**	**0**	**954**	**680**	**0**	**1510**	**0**	**0**	**2650**
0	4970	1430	0	0	380	130	0	0	1140	0	2270
0	3290	4290	0	400	0	0	0	1200	0	490	1140
0	2700	2380	0	0	0	620	0	1510	0	0	4770
0	**10960**	**8100**	**0**	**400**	**380**	**750**	**0**	**2710**	**1140**	**490**	**8180**
3925	0	0	0	1180	0	0	0	0	0	0	0
2270	2110	2110	3920	1080	0	670	0	0	0	990	0
1560	0	940	0	0	0	0	0	1100	0	780	730
0	2200	1000	0	0	490	0	0	0	0	0	1510
0	0	0	2380	0	0	0	0	0	2860	0	0
0	3650	1000	0	0	0	250	0	0	430	0	0
0	4240	760	0	810	0	0	0	0	1600	0	400
7755	**12200**	**5810**	**6300**	**3070**	**490**	**920**	**0**	**1100**	**4890**	**1770**	**2640**
0	1430	1000	0	950	0	300	0	430	0	0	0
0	0	0	0	0	0	0	0	0	0	0	870
3700	0	0	2380	2180	0	0	1060	0	0	510	1500
0	1450	5900	1160	1510	0	0	480	1450	0	0	0
0	0	0	0	0	0	0	0	0	0	0	1870
0	480	480	0	0	0	0	0	480	0	0	0
3600	0	3180	0	0	0	0	0	0	950	0	0
~~0~~	~~1310~~	~~1200~~	~~2110~~	~~0~~	~~0~~	~~400~~	~~0~~	~~500~~	~~0~~	~~0~~	~~0~~
0	0	0	0	0	0	0	0	0	0	0	0
7300	**3360**	**10560**	**3540**	**4640**	**0**	**300**	**1540**	**2360**	**950**	**510**	**4240**
0	1590	0	0	0	320	100	0	0	0	0	400
1110	0	850	850	0	0	290	0	0	0	0	200
0	1370	2240	0	0	0	0	0	0	0	0	0
~~0~~	~~475~~	~~1140~~	~~0~~	~~160~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~80~~
0	200	910	0	0	0	0	0	150	0	0	210
0	540	1590	0	0	0	110	0	0	0	0	410
1110	**3700**	**5590**	**850**	**0**	**320**	**500**	**0**	**150**	**0**	**0**	**1220**
17675	**40400**	**45410**	**12120**	**8110**	**2144**	**3150**	**1540**	**7830**	**6980**	**2770**	**18930**

7. Crude Oil and Petroleum Product Stocks

. A sluggish market for refined petroleum products largely explains the decline in product inventories.

Total crude oil and refined petroleum products held by refineries and major distributors totalled 12.5 million m^3 at the end of 1992. This level was down almost 2.0 million m^3 or 14% from 14.6 million m^3 recorded a year earlier. Of this volume, product stocks at 9.8 million m^3 were down 1.6 million m^3 or 14%. Crude oil stocks, were down 0.4 million m^3 or 13% to 2.6 million m^3.

As illustrated in figure 7.1, stocks have been on the decline since the early 1980's. This drop is attributed to number of factors, most notably a decline in refined product demand which over this period has led to a number of refinery closures. The two recessions and recent improvements in inventory management methods have been other factors underlying the decline in stocks.

Stocks at the end of 1992, were well below levels recorded during the 1970's and early 1980's, a period noted for its oil supply disruptions, rising prices and high product demand. Despite a short lived surge prior to the Iraq/Kuwait invasion, due primarily to plummeting product demand, stocks have fallen by about one third from levels recorded prior to the OPEC oil embargo of 1973-1974 and remain almost 50% below peak levels reached in the early 1980's.

At the end of 1992, oil and refined product stocks represented about 59 days * of demand. Days of supply or the ratio of stocks to consumption were about 10 days below that estimated at the onset of the 1973-1974 oil embargo. Stocks reached a high of 85 to 95 days of supply during the mid 1970's, falling to 70 days just prior to the Iraq/Kuwait crisis.

End-1992 stocks of refined petroleum products fell across all regions compared to the year before. Ontario recorded the largest volumetric decrease, down 469 000 m^3 or 13% to 2.4 million m^3. In Quebec, stocks were down 370 000 m^3 or 15% to 2.1 million m^3 while in the Prairies stocks were down 350 000 m^3 or 13% to 2.3 million m^3.

Stocks of 'main' petroleum products (representing about 38 days of supply), including motor gasoline, middle distillates and heavy fuel oil were down 1.6 million m^3 or 20% to 6.5 million m^3 from the year before. All components recorded decreases with motor gasoline recording the largest volumetric drop, down by 568 000 m^3 or 17% to 2.7 million m^3.

* *Stocks do not include estimates of crude oil held in pipelines tankage. If these stocks were to be included in the calculation, it is estimated that the number of days of supply would increase by about 7 days.*

Figure 7.1
Crude Oil and Petroleum Product Stocks
million m^3

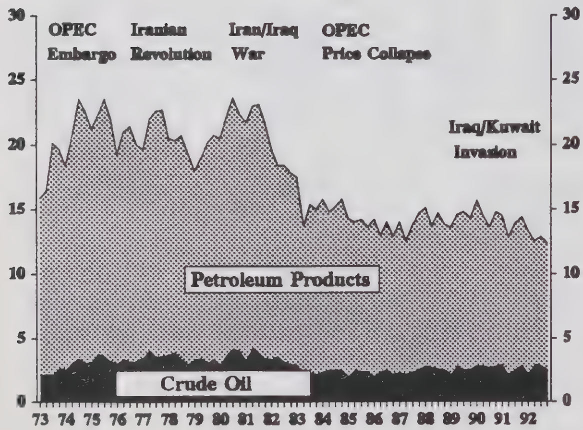


Figure 7.2
Days of Consumption

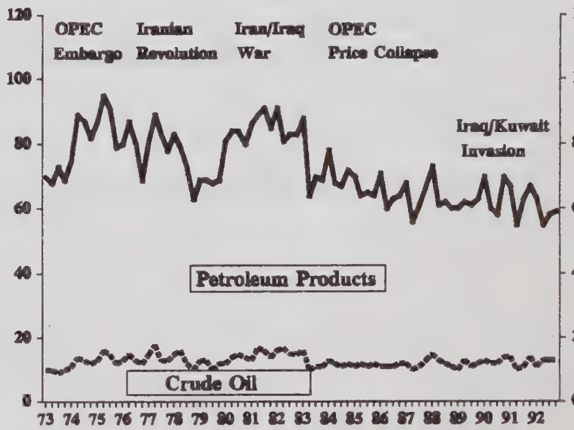


Figure 7.3
Total Petroleum Product Stocks
thousands of m^3

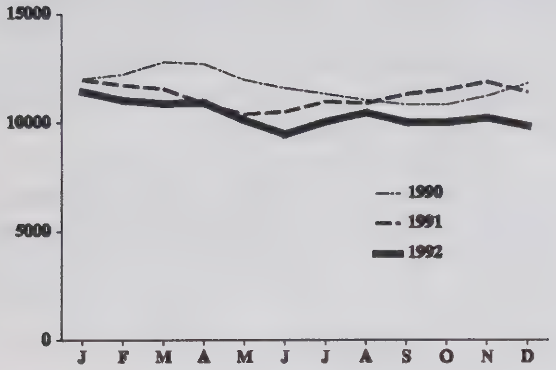


Figure 7.4
Motor Gasoline Stocks
thousands of m^3

Figure 7.5
Light Fuel Oil Stocks
thousands m^3

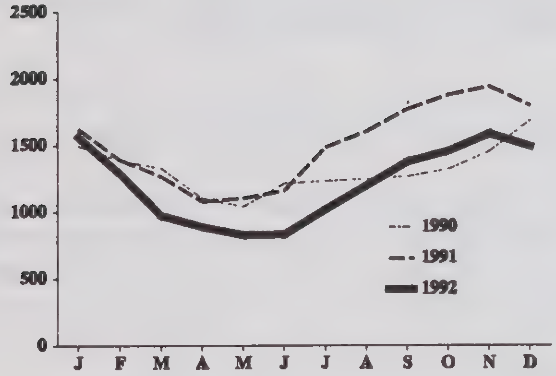


Figure 7.6
Diesel Fuel Oil Stocks
thousands m^3

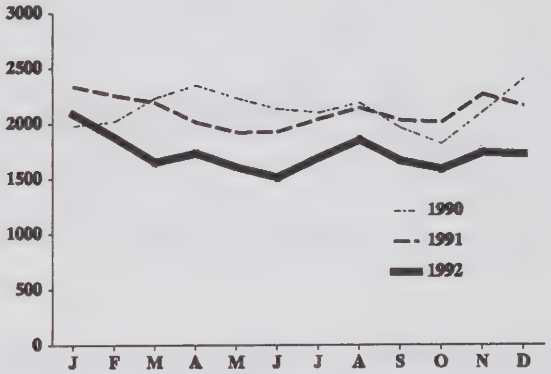


Figure 7.7
Heavy Fuel Oil Stocks
thousands m^3

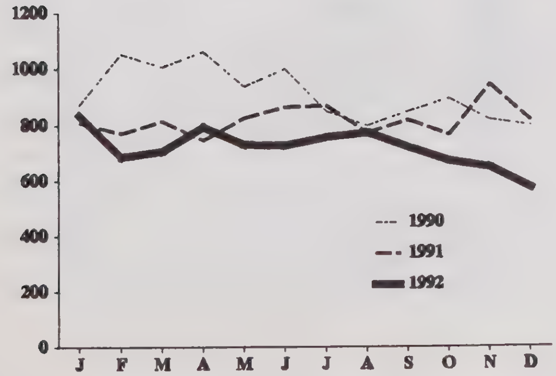
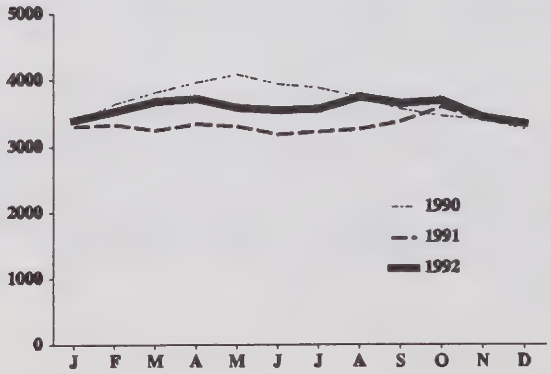


Figure 7.8
Other Petroleum Product Stocks
thousands m^3



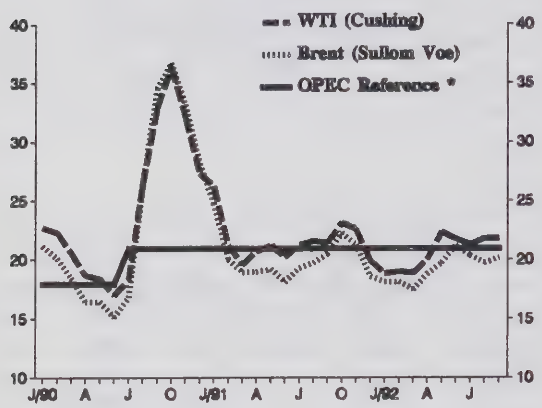
8. Crude Oil Prices

*. **In 1992, OPEC's inability to control members' production quotas and slow economic recovery in major oil consuming nations plagued the crude oil market.***

8.1 International Price Developments

Canadian crude oil prices are primarily affected by international supply and demand fundamentals and to a lesser extent local market conditions in Canada and the United States.

Figure 8.1
International Crude Oil Prices
US$/barrel



World oil markets were relatively well-supplied in 1992, with spot crude oil prices remaining stable throughout most of the year. West Texas Intermediate (WTI) averaged US$20.55/bbl, down $1.05/bbl from 1991. Prices did, however, rise to a high of US$22.40/bbl by mid-year, before moving down to about US$20/bbl by the end of the year. Although lower than the previous year, the price remained well below the US$32 to $35/bbl range recorded late in 1990 just prior to the Persian Gulf war.

Over the first quarter of the year sluggish demand for crude oil played a dominant role in world oil markets. By the end of the quarter, crude oil prices began to strengthen in response to OPEC's decision to restrain output, albeit marginally, for the March to June 1992 period.

Prices began to rise in the second quarter primarily as a result of OPEC's reaffirmation of previous production quotas into the third quarter. Prices were also influenced by rumours suggesting an embargo would be placed on Libyan oil; the decline in Former Soviet Union (FSU) oil production and a subsequent lowering of exports from the region; the continued absence of Iraqi crude oil from world oil markets; and a projected improvement in the U.S. economy.

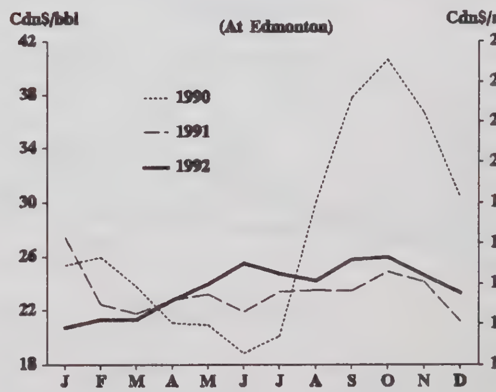
Third quarter crude prices were undermined by sluggish U.S. petroleum product demand and reports of high OPEC crude oil production. Late in the quarter, prices began to strengthen in response to a seasonal increase in product demand and reports of crude oil inventory drawdowns.

With the exception of a short-lived spike in mid-October, spot crude oil prices were under steady downward pressure during the fourth quarter due to high OPEC production, weak product demand in major consumer markets (particularly Europe and the United States), unexpectedly strong FSU oil exports, and mild weather in the northern hemisphere.

8.2 Domestic Crude Oil Postings

The average price of Canadian par crude (40° API, 0.5 % sulphur), as posted by four Canadian refiners, ranged between $20 to $26/bbl. By year-end, Par had dropped from an October high of $25.95/bbl to $23.11/bbl for a 1992 annual average of $23.51/bbl (US$19.45/bbl), marginally higher than the year before.

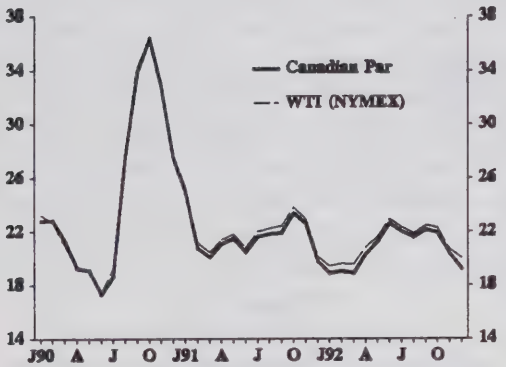
Figure 8.2
Canadian Par Crude Oil Postings



8.3 Light Crude Oil Prices at Chicago

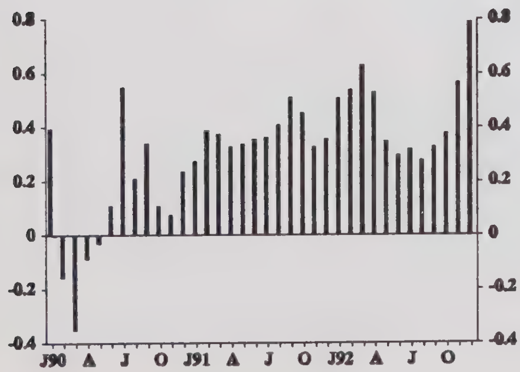
The following graphs compare the price of Canadian Par crude oil to the comparable WTI (NYMEX), U.S. benchmark crude (40°API), delivered to Chicago.

Figure 8.3.1
Light Crude Oil Prices at Chicago
(US$/bbl)



Over 1992, WTI (NYMEX) traded almost US$0.50/bbl above Canadian Par with the differential ranging between US$0.28 and $0.76/bbl. For the most part, this widening price differential is blamed on weak domestic demand and delivery problems associated with high IPL apportionment.

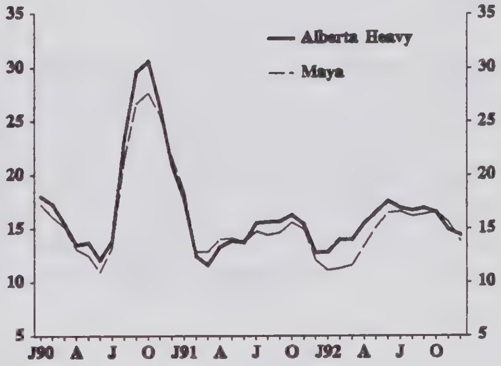
Figure 8.3.2
WTI/Canadian Par Differential
(At Chicago)



8.4 Heavy Crude Oil Prices at Chicago

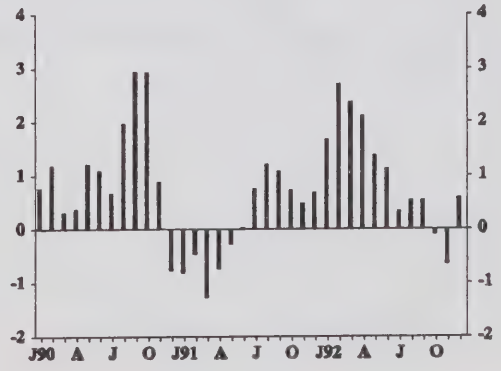
The following graphs compare the price of Alberta heavy crude oil (25.2° API) to Mexican Maya (22.5°API), delivered to Chicago.

Figure 8.4.1
Heavy Crude Oil Prices at Chicago
(US$/bbl)



Alberta heavy has generally been more expensive than Maya. Aside from the seasonal swings in demand, the deactivation of the Sarnia-Montreal pipeline late in 1990 has forced producers to search for alternative markets for displaced domestic heavy crude.

Figure 8.4.2
Alberta Heavy/Maya
(At Chicago)



8.5 Domestic Price Differentials

The differential between heavy and light crude oil is most notably affected by price trends established in the international market. Closer to home, the price gap can be affected by seasonal demand for heavy crude and the availability of upgrading capabilities.

Figure 8.4.2, illustrates the differential between the average monthly Canadian Par crude oil price and the average Alberta heavy crude oil postings. Similarly, the price of Canadian Par is compared to Alberta Light Sour Blend.

In 1991, producers were particularly concerned with a widening price differential. At that time, heavy crude prices were dampened by the entry of additional heavy crude supply into world markets to replace light crude lost during the Gulf crisis. This in turn resulted in higher prices for light crude oil. This situation led to the removal of some expensive domestic heavy crude oil production.

Typically, the price differential narrows during the summer months as a result of high demand for heavy crude for the production of asphalt. However, over the longer term, the availability of heavy crude upgrading capabilities improves the attractiveness of heavy crude as a refinery feedstock and tends to narrow the price differential.

Price differentials after a sharp increase in 1991, narrowed somewhat in 1992. This was primarily due to substantially higher demand for heavy crude driven by the installation of additional upgrading capacity at the Conoco refinery in Billings, Montana and the November start-up of the Husky Bi-provincial upgrader. Improved prices and rising upgrader demand led some heavy producers to announce the start-up of previously mothballed production.

Figure 8.5.1
Domestic Crude Oil Prices
(CDN$/bbl)

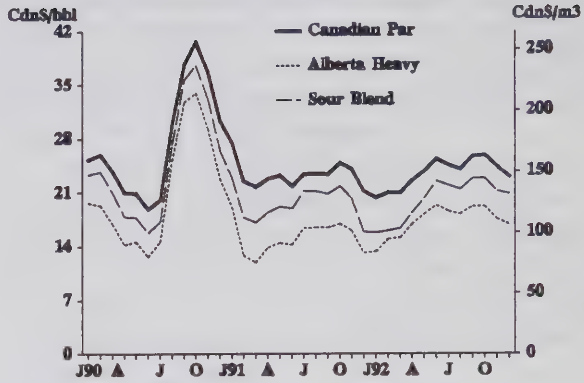
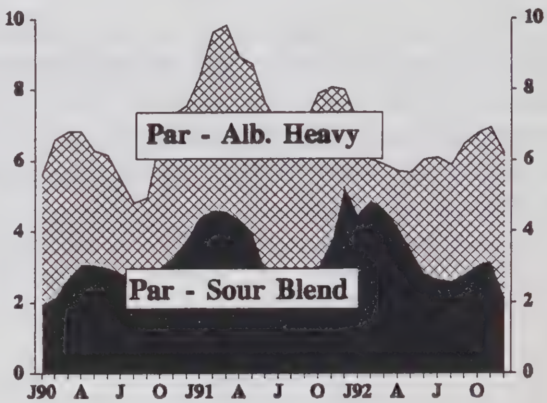


Figure 8.5.2
Crude Oil Price Differentials
(CDN$/bbl)



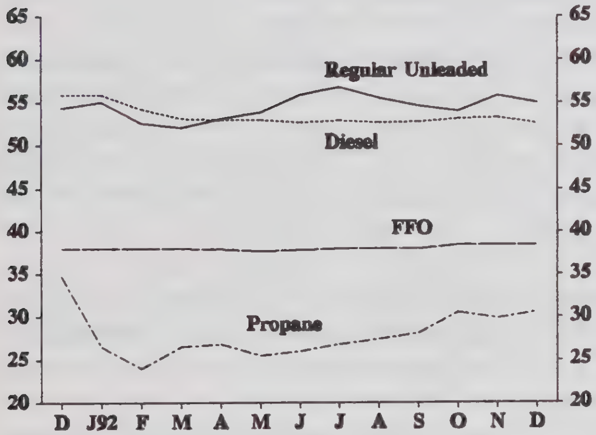
9. Refined Petroleum Product Prices

• Canadian petroleum product prices were relatively stable in 1992 compared to the price fluctuations experienced in 1991 during and after the Persian Gulf crisis.

9.1 Domestic Price Trends

According to a recent report, prepared by the *Petroleum Products Section of Canadian Oil Markets and Emergency Planning Division*, prices in 1992 were relatively stable, unlike the previous year when the Persian Gulf war had raised prices to their highest levels in years. Prices of regular unleaded gasoline were the lowest since 1989, whereas diesel and furnace fuel oil (FFO) prices remained higher than their pre-Gulf war levels. On an ex-tax basis, however, average annual prices of regular unleaded gasoline and diesel were lower than they had been in the last five years.

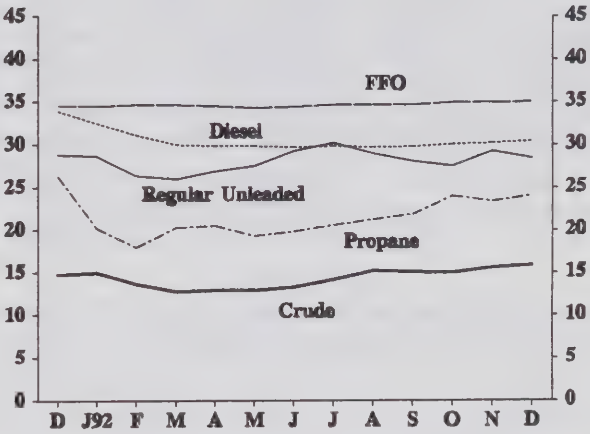
Figure 9.1.1
1992 Average Canadian Retail Prices
In Major Centres
cents per litre



Regular unleaded gasoline prices were generally lower than the post-war prices of 1991, in spite of a slight upturn in gasoline demand. Prices attained their lowest level in the first half of the year but firmed up during the summer season, when gasoline demand traditionally peaks. Over the 12-month period the Canadian monthly average price varied from a low of 52.1 ¢/l in March to a high of 56.8 ¢/l in July.

The most notable trend was the price decline in Atlantic Canada during the second half of the year, particularly in the Halifax market which was deregulated in July 1991. A steady decline in prices, resulting from increased competition and a decrease in the provincial road tax, brought the end-December price to a low of 52.9 ¢/l. This 7 ¢/l drop from January 1992 brings the Halifax price to the lowest recorded since 1989. Charlottetown, the only Canadian centre with a regulated market, experienced slight price drops.

Figure 9.1.2
1992 Average Canadian Retail Ex-Tax Prices
In Major Centres
cents per litre



This downward trend was not evident in western Canada, where prices are consistently below the Canadian average. Although price wars were common, several centres closed the year with higher prices than in December 1991. During specific price wars in Regina and Vancouver, prices tumbled to 39.9 ¢/l, the lowest price recorded in our 1992 survey. However, Calgary residents enjoyed the lowest average December price of the Canadian cities surveyed, 46.4 ¢/l.

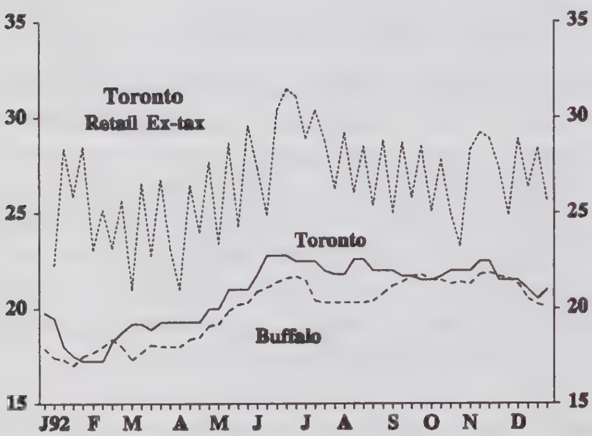
Diesel prices, which had not declined as quickly as gasoline prices following the Gulf war, began the year higher than those for regular unleaded gasoline. A marginal decline in demand dampened prices to around the 53 ¢/l mark, which was significantly lower than the post-war prices of 1991, but still higher than the 51 ¢/l average for the pre-war period of 1990. Of interest is Vancouver which experienced no price changes during the year. The largest average December 1991 to December 1992 decrease was registered in Montréal (-4.6 ¢/l).

As with regular unleaded gasoline, Calgary had the lowest diesel prices among the major centres, with a yearly average of 41.6 ¢/l.

Furnace fuel oil prices barely moved and remained close to 38 ¢/l. This, however, was higher than the pre-war prices of 1990.

Early in the year, warmer than normal temperatures in western Canada resulted in high inventory levels for propane, sparking some fierce price wars for automotive propane. In Winnipeg the price fell to a low of 15.7 ¢/l. However, by mid-year, western markets had stabilized and prices were only marginally lower at the end of 1992 than they had been in December 1991. Although prices in eastern Canada are traditionally higher than the rest of the country, the Atlantic region saw its prices drop more significantly, over the year, a trend that was also evident with gasoline. The drop in eastern Canadian prices resulted in a net decline in the Canadian average of about 6 ¢/l by year-end, when compared to December 1991.

Figure 9.1.3
Comparison of Wholesale vs Retail Prices
(cents per litre)



Canadian and American wholesale prices generally followed the same trend and all experienced seasonal changes. Although the Canadian prices were generally higher, prices in the American centres surpassed their Canadian counterparts at least once during the year. The price differentials between the Canadian and American wholesale prices varied from centre to centre. During the 12-month period, Vancouver vs Seattle prices recorded the largest differential at 9.4 ¢/l. Montréal vs New York registered 3.8 ¢/l and Toronto vs Buffalo, 2.3 ¢/l. In all three cases the Canadian prices were higher.

A good example of how retail prices are influenced by market forces and wholesale prices is evident in Figure 9.1.3. Toronto was chosen for this comparison because of its influence on the average Canadian price and because of its intense competition with Buffalo. In order to remove any effect of tax increases, the ex-tax price was used.

9.2 Cost Components

Readers are reminded of the theoretical nature of this analysis, which is provided for illustrative purposes. Individual company positions may exhibit considerable variation from averages used in this report. Local market conditions, particularly variations in stock levels between companies, can also have a significant impact on the rapidity of price changes and the composition of pump prices.

A breakdown of the various components making up the average pump price of regular unleaded gasoline indicates that increases in average crude costs and provincial taxes were partially offset by reductions in industry margins during the year.

The average Canadian crude cost decreased from January to May and then gradually increased over the second half of the year. By December, the average crude cost was 1.1 ¢/l higher than it had been in December 1991 and accounted for 29% of the average retail price.

The federal tax components, the Goods and Services Tax (GST) and the excise tax, remained unchanged in 1992. Price fluctuations over the year resulted in minor changes in the GST, which is based on 7% of the retail price, but the federal tax component on regular unleaded gasoline ended the year at 11.9 ¢/l, unchanged from December 1991. The average provincial tax increased by 0.8 ¢/l in January and then remained relatively stable throughout the rest of the year. By December, the combined federal and provincial tax components accounted for 48% of the pump price, up from 47% last year.

The residual component, refining and marketing costs and profits, fluctuated from a high of 14.2 ¢/l in June to a low of 8.9 ¢/l in December, down 1.6 ¢/l from December 1991. Retail margins were relatively stable over the year ranging from 3.4 to 3.7 ¢/l.

9.3 Consumption Taxes On Petroleum Products Components

On average in 1992 petroleum product consumption taxes did not change significantly. The Federal Excise Tax remained unchanged during the year at 8.5 ¢/l for gasoline and 4.0 ¢/l for diesel. While the GST on regular unleaded gasoline was unchanged at 3.4 ¢/l from December 1991 to December 1992, there were increases on the other grades of gasoline. GST increases on the middle and premium grades were 0.1 ¢/l and 0.2 ¢/l, respectively, to 3.7 ¢/l and 4.0 ¢/l. The average provincial tax on regular unleaded gasoline increased by 0.9 ¢/l.

On August 17th, the Newfoundland government announced a decrease in propane taxes of 6.7 ¢/l in order to support a federal/provincial/industry pilot project to create a market for automotive propane. Also in Newfoundland, an increase of 2.0 ¢/l in the gasoline and diesel taxes was announced on December 4th. Newfoundland now has the highest diesel tax in Canada and the gasoline tax is second only to Quebec's rate.

In the last six months of 1992 the trucking industry in Quebec had lobbied for a full refund on the diesel tax. The Quebec government announced a reduction of 1.9 ¢/l on diesel effective November 25th. When the impact of the GST (7%) and the Quebec Sales Tax (8%) are factored in, the diesel tax was effectively reduced by 2.2 ¢/l.

9.4 Price Differentials

Between December 1991 and December 1992, gasoline price differentials continued to increase across Canada as the prices for premium and middle gasolines (up 3%) increased more than the price of regular unleaded (up 1%). As environmental standards are tightened, refinery processes will become increasingly sophisticated and costly. Widening differentials is one method of recovering some of the money required to fund the changes.

Competition also contributes to the differences in price changes between regular unleaded and the higher grades of gasoline. Regular unleaded gasoline accounts for almost 70% of the total gasoline sold in the 10 centres included in our Canadian average. Often the regular unleaded gasoline price is the only price posted making it easy for consumers to comparison shop. Also competition is usually stronger for products with higher sales.

In all centres across Canada the price differential between regular and mid-grade gasoline increased. The regulated Charlottetown market had the lowest differential, 1.3 ¢/l. In the other centres, the differential increased by as much as 1.5 ¢/l from December 1991 to December 1992 and ranged from 2.9 ¢/l in Saint John to 4.5 ¢/l in Montréal by year-end. The spread between premium and regular grades increased in all centres except Charlottetown and Halifax and ranged from 2.4 ¢/l in Charlottetown to 8 ¢/l in Montréal and Toronto.

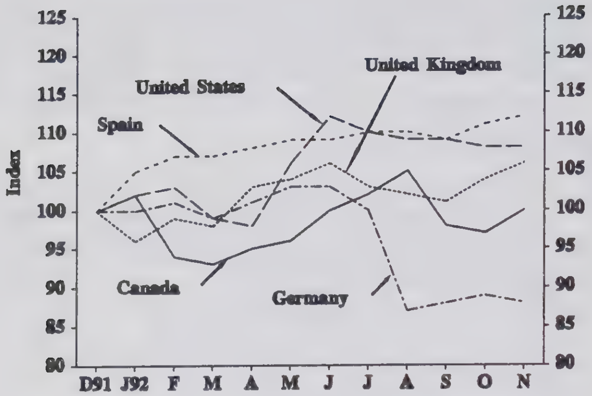
9.5 Canada vs Other Countries

The average U.S. retail price of motor gasoline increased by 5.4 Canadian ¢/l between November 1991 and November 1992, while the Canadian average rose by 0.2 ¢/l. However, the greatest part of the increase in the U.S. price, 4.5 ¢/l, can be attributed to the weakening Canadian dollar.

The price differential fell 5.2 ¢/l to 16.1 ¢/l, the second lowest differential in more than three years. Higher consumption taxes in Canada continue to account for most of the difference, 90% in November 1992.

While gasoline is more expensive in Canada than in the United States, it is generally less expensive than gasoline in other industrialized countries. Canadian gasoline prices were less than half the price of gasoline in most of the International Energy Agency (IEA) member countries throughout 1992. Higher prices in other IEA countries are generally the result of high consumption taxes on gasoline. In some countries the tax accounts for more than 75% of the retail price.

Figure 9.5
Gasoline Price Indices
December 1991 = 100



Gasoline prices were fairly stable in most countries during 1992 with changes averaging less than 5%. Exceptions to this trend were observed in Germany where prices fell about 12% and in Spain where prices increased almost 13%.

9.6 Structural Changes

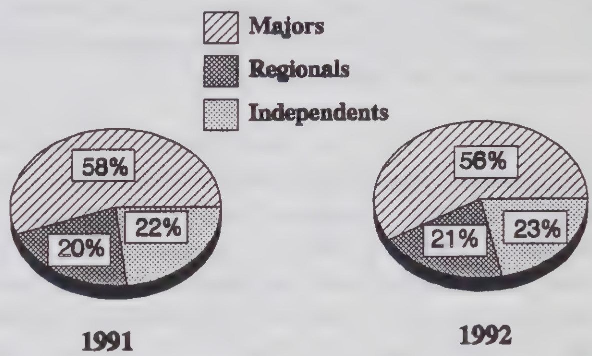
Structural changes in the downstream petroleum industry during 1992 were mostly driven by rationalization and restructuring in the marketplace. The number of retail outlets declined to 17,815 from 18,792, a 5% drop over 1991. In their attempts to reduce the cost per unit of product sold, some marketers closed their less efficient stations to increase the volume sold per outlet.

Retail outlet reductions occurred in all regions in Canada with the exception of Alberta and British Columbia. The Prairie region recorded a 4% decrease, since there was a reduction in outlets of 9.5% in Saskatchewan and 9.9% in Manitoba. Significant decreases in the number of outlets were also recorded in Ontario (8%) and Quebec (6%).

Major integrated companies, with higher overhead costs than those of the regional and independent marketers, were the most aggressive in their rationalization programs. They were not, however, always able to hold on to their market share in the process.

At the end of the third quarter 1992, majors accounted for 56% of the gasoline sales in the 13 major centres across Canada, a drop of 2% from the same period in 1991. Regional and independent marketers each gained 1%, holding 21% and 23% of the market, respectively, at the end of the third quarter 1992. Independents, who have a stronger position in the Prairies, made larger gains there than in other parts of the country. Similarly, the regional refiners with a stronghold in the Atlantic provinces increased their market share more significantly there than in other regions. Charlottetown was a notable exception where, in the absence of an independent sector, the majors gained strength at the expense of the regional marketers.

Figure 9.5
Market Share



In Nova Scotia, self-serve outlets increased gradually over the year. Prior to July 1991, self-serve outlets were prohibited under the Gasoline and Fuel Oil Licensing Act. The gap between full-serve and self-serve prices widened towards the end of the year, to 1.8 ¢/l from 1.4 ¢/l in March 1992.

Appendix I
Production of Crude Oil and Equivalent
(000 m^3/d)

		4Q	1991 Year	1Q	2Q	3Q	4Q	1992 Year
A.	**Light and Equivalent**							
	Conventional							
	Alberta	112.5	112.2	114.2	108.1	111.1	110.3	111.2
	B.C.	5.7	5.5	5.5	5.5	5.5	5.6	5.5
	Saskatchewan	11.4	11.4	11.4	11.4	11.6	11.7	11.5
	Manitoba	1.9	1.9	1.8	1.8	1.7	1.8	1.8
	NWT	5.2	5.2	5.3	5.2	5.6	4.4	5.1
	Ontario	0.6	0.6	0.6	0.7	0.6	0.7	0.6
	Nova Scotia	-	-	-	0.6	3.5	2.2	1.6
	Total	**137.3**	**136.5**	**138.8**	**134.2**	**139.6**	**136.7**	**137.3**
	Synthetic							
	Suncor	9.1	9.6	10.2	6.4	9.8	9.6	9.0
	Syncrude	29.6	26.3	27.6	26.4	27.2	32.9	28.5
	Total	**38.7**	**35.9**	**37.8**	**32.8**	**37.1**	**42.5**	**37.6**
	Pentanes Plus(excl. diluent)**5.6**	**9.0**	**8.6**	**8.9**	**7.3**	**9.3**	**7.9**	**8.4**
	Total Light	**185.0**	**179.3**	**185.6**	**174.3**	**185.9**	**187.1**	**183.2**
B.	**Heavy Crude**							
	Alberta							
	Conventional	32.1	30.6	33.8	33.0	35.6	36.0	34.6
	Bitumen	16.5	19.5	18.4	20.7	21.8	20.3	20.3
	Diluent	8.6	9.3	9.7	9.6	8.6	11.1	9.7
	Total	**57.2**	**59.4**	**61.9**	**63.3**	**65.9**	**67.4**	**64.6**
	Saskatchewan							
	Conventional	23.4	22.3	23.4	24.0	25.3	25.4	24.5
	Diluent	3.3	3.1	3.4	3.3	3.2	3.7	3.4
	Total	**26.7**	**25.4**	**26.8**	**27.3**	**28.4**	**29.1**	**27.9**
	Total Heavy	**83.9**	**84.8**	**88.7**	**90.6**	**94.4**	**96.5**	**92.5**
C.	**Total Production**	**268.9**	**264.1**	**274.3**	**264.9**	**280.3**	**283.6**	**275.8**

Appendix II
Supply and Disposition of Crude Oil and Equivalent
(000 m^3/d)

	4Q	1991 Year	1Q	2Q	3Q	4Q	1992 Year
A. Light and Equivalent							
Supply							
Production	185.0	179.4	185.6	174.3	185.9	187.1	183.2
Plus: Upgraders	3.3	2.0	3.4	0.7	4.4	10.5	4.7
Statistical Diff.	8.1	8.1	13.7	11.1	11.8	4.4	10.0
Net Supply	196.4	189.5	202.7	186.1	202.1	202.0	198.0
Domestic Demand							
Atlantic	0	0	0	0	0	2.1	0.5
Quebec	0	2.7	0	0	1.4	0	0.4
Ontario	63.0	58.8	61.3	51.0	58.5	60.4	57.8
Prairies	47.8	46.6	43.2	40.5	46.5	42.4	43.2
B.C.	20.4	18.9	20.0	21.2	21.4	19.7	20.5
Total	131.1	127.0	124.4	112.7	127.8	124.6	122.4
Exports	**65.2**	**62.4**	**78.3**	**73.4**	**74.3**	**77.4**	**75.6**
Total Demand	**196.3**	**189.4**	**202.7**	**186.1**	**202.1**	**202.0**	**198.0**
B. Heavy Crude (Blended)							
Supply							
Production	83.9	84.7	88.7	90.6	94.4	96.5	92.5
Recycled Diluent	0.5	1.0	0.9	1.0	2.1	1.0	1.3
Less: Upgrader Feedstock	0	0	0	1.8	2.4	4.1	2.1
Statistical Diff.	(5.9)	(5.0)	(11.9)	(13.9)	(6.3)	(16.4)	(12.1)
Net Supply	78.5	80.7	77.7	75.9	87.7	77.1	79.6
Domestic Demand							
Atlantic	0	0	0	0	0	0	0
Quebec	0.1	0.1	0	0	0	0	0
Ontario	9.3	10.2	7.7	11.2	11.6	7.9	9.6
Prairies	10.7	10.3	11.4	8.9	13.9	10.6	11.2
B.C.	0.7	0.6	0.6	0.5	0.9	1.0	0.8
Total	20.8	21.1	19.6	20.6	26.3	19.5	21.5
Exports	**57.8**	**59.6**	**58.1**	**55.3**	**61.4**	**57.6**	**58.1**
Total Demand	**78.6**	**80.7**	**77.7**	**75.9**	**87.7**	**77.1**	**79.6**

Appendix III
Crude Oil Exports by Destination
(000 m³/d)

				1991				1992
		4Q	Year	1Q	2Q	3Q	4Q	Year
U.S. PAD Districts *								
I	Light	6.8	7.2	7.4	8.3	8.1	7.8	7.9
	Heavy	1.5	1.3	1.3	1.4	1.6	1.3	1.4
	Total	**8.3**	**8.5**	**8.7**	**9.7**	**9.7**	**9.1**	**9.3**
II	Light	44.5	41.9	53.6	51.6	48.7	41.8	50.9
	Heavy	49.2	51.8	53.5	48.6	54.4	51.3	52.0
	Total	**93.7**	**93.7**	**107.1**	**100.2**	**103.1**	**100.9**	**102.9**
III	Light	0	0	0	0	2.4	0.8	1.0
	Heavy	2.5	1.5	0	0	0	0	0
	Total	**2.5**	**1.5**	**0**	**0.8**	**2.4**	**0.8**	**1.0**
IV	Light	12.3	11.1	13.0	8.7	10.4	10.5	10.7
	Heavy	3.4	3.0	2.5	4.9	4.7	4.8	4.2
	Total	**15.7**	**14.0**	**15.5**	**13.6**	**15.1**	**15.3**	**14.9**
V	Light	0.9	1.3	2.5	2.9	3.1	6.0	3.5
	Heavy	0.4	0.5	0	0.5	0.7	0.2	0.3
	Total	1.3	1.8	**2.5**	**3.4**	**3.8**	**6.2**	**3.8**
Total U.S.	**Light**	**64.5**	**61.5**	**76.5**	**72.3**	**72.7**	**74.7**	**74.0**
	Heavy	**57.0**	**58.0**	**57.3**	**55.4**	**61.4**	**57.6**	**57.9**
	Total	**121.5**	**119.5**	**133.8**	**127.7**	**134.1**	**132.3**	**131.9**
Offshore	Light	0.9	0.6	1.5	1.1	1.5	2.7	1.7
	Heavy	0.9	1.4	0.9	0	0	0	0.2
	Total	**1.8**	**2.0**	**2.4**	**1.1**	**1.5**	**2.7**	**1.9**
Total	**Light**	**65.4**	**62.1**	**78.0**	**73.4**	**74.2**	**77.4**	**75.7**
	Heavy	**57.9**	**59.4**	**58.2**	**55.4**	**61.4**	**57.6**	**58.1**
	Total	**123.3**	**121.6**	**136.2**	**128.8**	**135.6**	**135.0**	**133.8**

** U.S. Petroleum Administration for Defense (PAD) Districts*

Appendix IV
Pipeline Deliveries
(000 m^3/d)

		4Q	Year	1991 1Q	2Q	3Q	4Q	1992 Year
A.	**Trans Mountain Pipe Line (TMPL)**							
	Domestic Deliveries							
	Light Crude	9.7	16.8	19.0	21.1	20.2	20.6	20.2
	Heavy Crude	0.3	0.5	0	0.2	0.3	0.3	0.2
	Semi Refined Products	3.2	3.9	3.1	1.7	2.6	2.7	2.5
	Refined Products	2.9	2.5	2.7	2.4	2.8	2.7	2.6
	Total	26.1	23.7	24.8	25.4	25.9	26.3	25.6
	Foreign Deliveries							
	Tankers	4.5	4.0	4.0	4.6	2.3	4.2	3.8
	Puget Sound Area	0.8	1.1	1.7	2.2	3.0	4.4	2.8
	Total	**5.3**	**5.1**	5.7	6.8	5.3	8.6	6.6
	Total TMPL	**31.4**	**28.8**	**30.4**	**32.2**	**32.8**	**34.9**	**32.2**
B.	**Interprovincial Pipe Line (IPL)**							
	Domestic Deliveries							
	Light Crude	74.3	74.1	74.0	63.3	67.9	71.1	69.2
	Heavy Crude	14.5	13.8	13.6	15.4	17.8	13.2	15.0
	Other (1)	28.1	27.2	31.3	28.6	29.3	30.9	30.0
	Total	116.9	115.1	118.9	107.3	115.0	115.2	114.2
	Foreign Deliveries							
	Light Crude	51.4	49.5	59.5	58.0	56.7	57.9	58.0
	Heavy Crude	50.6	53.2	54.8	50.1	56.0	46.4	53.3
	Other (1)(2)	7.0	6.7	6.6	5.5	5.4	11.3	5.8
	Total	109.0	109.4	120.9	113.6	118.1	115.6	117.1
	Total IPL	**225.9**	**224.5**	**239.8**	**220.9**	**233.1**	**230.8**	**231.3**
C.	**Pipelines to Montreal**							
	IPL Deliveries							
	To Montreal	0	2.4	0	0	0	0	0
	For Export/Transfer	0	0	0	0	0	0	0
	Total IPL	0	2.4	0	0	0	0	0
	Portland-Montreal							
	Montreal Imports (3)	29.1	25.0	28.4	20.8	29.3	27.7	26.5
	Total Montreal Receipts	**29.1**	**27.4**	**28.4**	**20.8**	**29.3**	**27.7**	**26.5**

(1) includes petroleum products and NGL's. *(3) may include cargos imported directly into Montreal*
(2) includes some US domestic crudes delivered to the U.S.

Appendix V
Canadian Refinery Receipts
(000 m³/d)

	1991 4Q	1991 Year	1992 1Q	1992 2Q	1992 3Q	1992 4Q	1992 Year
A. Domestic Receipts							
Light & Equivalent							
Atlantic	0	0	0	0	0	2.1	0.5
Quebec	0	0	0	0	1.4	0	0.4
Ontario	63.0	58.9	61.3	51.0	58.4	60.4	57.8
Prairies	47.7	46.7	43.2	40.5	46.6	42.4	43.2
B.C.	20.4	18.8	19.9	21.2	21.4	19.7	20.6
Total	**131.1**	**124.4**	**124.4**	**112.7**	**127.8**	**124.6**	**122.5**
Heavy							
Atlantic	0	0	0	0	0	0	0
Quebec	0.1	0	0	0	0	0	0
Ontario	9.3	10.2	7.7	11.2	11.6	7.8	9.6
Prairies	10.6	10.2	11.4	8.9	13.8	10.6	11.2
B.C.	0.7	0.6	0.6	0.5	0.9	1.0	0.8
Total	20.7	21.0	**19.7**	**20.6**	**26.3**	**19.4**	**21.6**
Other (incl. partially processed)							
Atlantic	0.2	0	0.3	0	0	0	0
Quebec	0	0.1	0	0	0	0	0
Ontario	4.8	4.5	4.9	4.0	4.9	5.1	4.8
Prairies	2.3	3.9	3.8	1.5	3.0	3.4	2.9
B.C.	3.5	4.1	3.3	2.0	2.8	3.1	2.8
Total	**10.6**	**12.9**	**12.0**	**7.5**	**10.7**	**11.6**	**10.5**
Total Domestic Receipts							
Atlantic	0	0.3	0	0	0	2.1	0.5
Quebec	0.1	0.1	0	0	1.4	0	0.4
Ontario	77.1	73.6	73.9	66.2	74.9	73.3	72.2
Prairies	60.6	60.8	58.4	50.9	63.4	56.4	57.3
B.C.	24.6	23.5	23.8	23.7	25.1	23.8	24.2
Total	**162.4**	**158.3**	**156.1**	**140.8**	**164.8**	**155.6**	**154.6**
B. Crude Oil Imports							
Atlantic	54.2	49.7	45.2	42.3	43.8	46.3	44.4
Quebec	47.8	41.9	43.5	39.7	46.1	45.9	43.8
Ontario	0.1	0.4	0.2	0.9	0.2	0.4	0.5
Prairies	0	0	0	0	0	0	0
B.C.	0	0	0	0.1	0	0	0
Total	**102.1**	**92.0**	**88 .9**	**83.0**	**90.1**	**92.6**	**88.7**
C. Total Receipts							
Atlantic	54.2	50.0	45.2	42.3	43.8	48.4	44.9
Quebec	47.9	42.0	43.5	39.7	47.5	45.9	44.2
Ontario	77.2	74.0	74.1	67.1	75.1	73.7	72.7
Prairies	60.6	60.8	58.4	50.9	63.4	56.4	57.3
B.C.	24.6	23.5	23.8	23.8	25.1	23.8	24.2
Total	**264.5**	**250.3**	**245.1**	**223.8**	**254.9**	**248.2**	**243.3**

Appendix VI
International and Domestic Crude Oil Prices
(US$/bbl)

	At Source			At Chicago			At Montreal	
	CDN Par	Brent	WTI NYMEX	CDN Par	Brent	WTI NYMEX	CDN Par	Brent
Jan. 1991	23.74	23.63	24.70	25.03	25.91	25.30	25.31	25.62
Feb.	19.48	19.29	20.56	20.76	21.82	21.15	21.05	21.34
Mar.	18.83	19.64	19.88	20.11	21.66	20.48	20.39	21.40
Apr.	19.80	19.34	20.82	21.08	21.09	21.41	21.37	21.00
May	20.22	19.24	21.25	21.50	21.29	21.84	21.78	20.92
Jun.	19.15	18.17	20.20	20.44	20.35	20.80	20.72	19.78
Jul.	20.38	19.46	21.43	21.67	21.46	22.03	21.92	21.09
Aug.	20.55	19.72	21.65	21.84	21.78	22.25	22.09	21.31
Sep.	20.64	20.52	21.86	21.93	22.47	22.45	22.20	22.01
Oct.	22.07	22.21	23.23	23.37	24.14	23.83	23.64	23.71
Nov.	21.35	21.13	22.38	22.65	23.01	22.98	22.92	22.61
Dec.	18.49	18.28	19.53	19.77	19.95	20.13	20.04	19.72
Avg. 1991	**20.39**	**20.05**	**21.46**	**21.68**	**22.08**	**22.05**	**21.95**	**21.71**
Jan. 1992	17.61	18.18	18.82	18.91	19.87	19.42	19.22	19.64
Feb.	17.77	18.11	19.01	19.06	19.76	19.60	19.36	19.51
Mar.	17.63	17.60	18.95	18.92	19.17	19.55	19.21	18.99
Apr.	19.03	18.85	20.26	20.32	20.44	20.85	20.61	20.11
May	19.87	19.83	21.00	21.24	21.46	21.59	21.57	21.19
Jun.	21.29	21.19	22.36	22.66	22.79	22.96	22.99	22.53
Jul.	20.65	20.23	21.74	22.02	21.89	22.34	22.99	21.61
Aug.	20.24	19.79	21.29	21.60	21.47	21.88	21.94	21.15
Sep.	21.07	20.21	21.92	22.19	21.87	22.51	22.38	21.55
Oct.	20.82	20.34	21.71	21.94	22.04	22.30	22.12	21.72
Nov.	19.30	19.22	20.36	20.41	21.00	20.96	20.59	20.65
Dec.	18.17	18.22	19.43	19.27	19.99	20.03	19.45	19.72
Avg. 1992	**19.45**	**19.31**	**20.57**	**20.71**	**20.98**	**21.17**	**21.04**	**20.70**

Appendix VII
Average Regular Unleaded Gasoline Prices
(Self-Serve)
1991-1992

	1991	---- 1992 ----			
	Dec. 31	**Mar. 31**	**June 30**	**Sep. 29**	**Dec. 29**
	----cents per litre----				
St John's (NFLD)	61.8	60.9	60.9	59.9	56.8
Charlottetown	61.1	60.3	60.0	60.4	58.5
Halifax	59.9	59.0	58.9	58.0	52.9
Saint John (N.B.) *	60.0	56.8	54.5	56.9	55.1
Montreal	63.8	59.0	61.8	59.5	59.8
Toronto	47.7	49.6	58.1	55.3	52.2
Winnipeg	49.8	46.8	53.9	47.9	53.9
Regina	50.9	41.9	43.9	49.9	56.9
Calgary	49.2	42.5	51.6	49.0	43.6
Vancouver	49.6	55.9	56.9	47.7	55.9
Average	**53.7**	**52.4**	**57.4**	**54.2**	**54.3**
Consumption taxes include:					
Federal	11.9	11.8	12.2	12.0	11.9
Provincial	13.1	13.8	14.0	13.9	14.0

* *Full-Serve*

Appendix VIII
Consumption Taxes on Petroleum Products
(December 1992)

	Ad valorem		Gasoline			Diesel
	Mogas	Diesel	Reg UL	Mid UL	Prem UL	
	----------%----------		------------------ (cents per litre) --------------			
Federal Taxes						
Estimated GST (7%)			3.4	3.7	4.0	3.3
Excise			8.5	8.5	8.5	4.0
Provincial Taxes						
Newfoundland [(a)]			15.7	15.7	15.7	17.6
Prince Edward Island	23	26	11.7	11.7	11.7	11.7
Nova Scotia	24.5	31.5	11.8	11.8	11.8	14.0
New Brunswick			10.7	10.7	10.7	13.7
Quebec [(b)]			18.9	19.3	19.5	16.7
Ontario			14.7	14.7	14.7	14.3
Manitoba			10.5	10.5	10.5	10.9
Saskatchewan			13.0	13.0	13.0	13.0
Alberta			9.0	9.0	9.0	9.0
British Columbia [(c)]			10.0	10.0	10.0	10.5
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	(d)	9.6	9.6	9.6	8.2

(a) The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay, Labrador.

(b) Reduced by varying amounts in certain remote areas and within 20 kilometres of the provincial and U.S. borders.

(c) Additional transit tax of 3.0 cents per litre in Vancouver.

(d) 85% of gasoline tax.

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional area	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Synthetic crude oil	Crude oil production treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

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Energy Sector
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The Canadian Oil Market

Overview

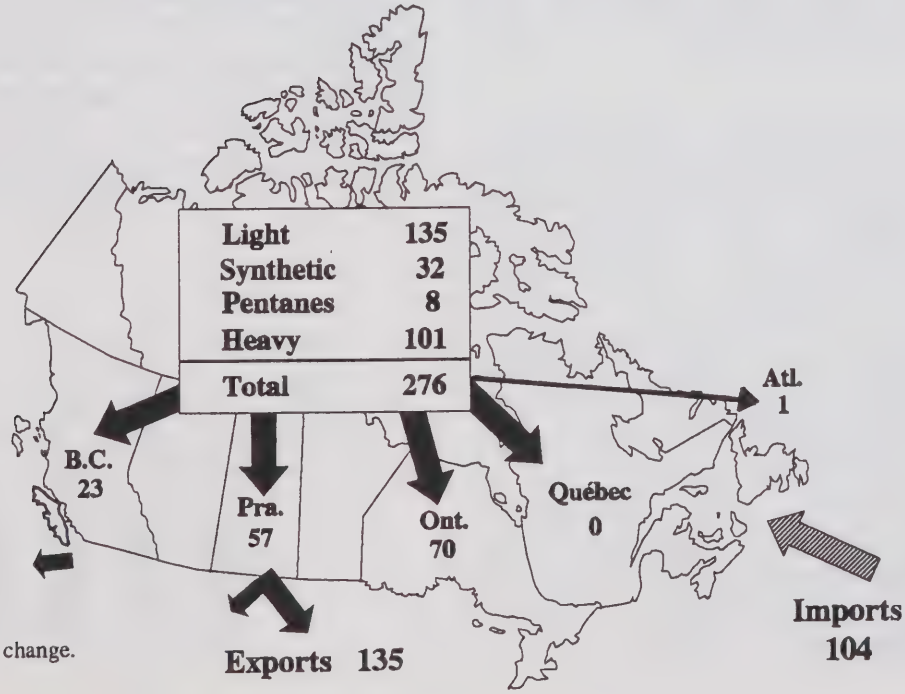
Despite a modest increase from last year, demand for refined petroleum products in Canada remained weak during the first quarter of 1993. Product demand rose modestly to 216 000 m^3/d, year-over-year. The modest growth in sales was consistent with a hesitant economic recovery.

Total crude oil production has been slowly on the rise over the last couple years. Recent price stability (and in particular the strength of heavy crude prices), Alberta's royalty relief package, and rising horizontal drilling activity have helped to stimulate production. While light crude oil production continued to slide, due in part to a prolonged maintenance program at the Syncrude oil sands plant early in the quarter, heavy crude production has benefited from rising upgrader demand.

About 65% of all available drilling rigs were operating in western Canada during the first quarter of 1993. This rate of activity was a far cry from the dismal drilling industry performance recorded a year earlier.

Much of the increase in drilling activity can be attributed to Alberta's October 1992 crude oil royalty relief package which was designed to stimulate drilling activity in that province where the bulk of oil drilling takes place. The package, which among other incentives, lowered the provincial base royalty structure was originally to have ended March 31 but was extended to include August 1993 drilling.

First Quarter 1993
Supply and Disposition of Crude Oil and Equivalent
000 m^3/d



* Total does not include inventory change.

First quarter crude oil supply was bolstered by a 17% rise in crude oil imports, year over year, to 104 000 m^3/d. Most of this increase can be attributed to Atlantic region refiners offshore processing agreements, and the impact of the mid-1991 closure of the Sarnia to Montreal pipeline.

Import receipts in the first quarter were almost evenly distributed between Atlantic and Quebec refiners (Ontario imports were negligible). Atlantic refiners received crude from both OPEC and non-OPEC countries, while Quebec relied predominantly on non-OPEC crude oil. North Sea crudes accounted for 81% of Quebec import receipts, while just over half of Atlantic region imports came from OPEC countries.

Crude oil apportionment continued to be a problem on Canadian pipelines. First quarter apportionment on the Interprovincial Pipe Line averaged 20% having reached a high of 26% in January.

Refinery receipts at 253 000 m^3/d were almost 9% higher than a year earlier with much of the rise attributable to a large downward adjustment in crude oil and inventory levels in eastern Canada which lowered receipts in the first quarter of 1992. Higher crude runs, again in eastern Canada, was the other factor underlying the increase in demand in 1993. While demand for crude oil still remained relatively weak Canadian producers were compensated by high exports of crude to the United States.

Canadian heavy crude producers have seen their market opportunities grow in the past year with the completion of the Conoco's Coker in Billings, Montana, and the Lloydminster upgrader. Their opportunities might improve even more once the 4 000 m^3/d Conoco pipeline expansion is completed. However, there are concerns that the upturn in demand for Canadian heavy crude oil in the export market might be short-lived. U.S. refiners might eventually take lower volumes of Canadian heavy crude as the U.S. federal government imposes stiffer environmental legislation. On that matter, regulation requiring sulphur content in most diesel fuel to drop to 0.05% from 0.5% could shrink the market for Canadian heavy crude because some U.S. refiners may not be willing to invest in desulfurization equipment.

Refinery throughput in the first quarter increased by about 3% from a year earlier, increasing in tandem with the modest rise in refined product sales in both the domestic and export markets. This resulted in a four percentage point increase in the national rate of refinery utilization, to 82%.

The highest refinery utilization rate was recorded in British Columbia, where it approached 95%. A rise in refinery utilization in Quebec was in part due to greater interregional transfers of refined products from Quebec to the Atlantic region. Because of a new processing agreement, a greater portion of refined products manufactured in the Atlantic is now destined for the export market. So as to maintain supply in the Atlantic, refined products are being shipped in from Quebec.

Ontario's recorded the lowest refinery utilization rate at 75% The lower rate of refining activity in Ontario can be attributed soft prices and scheduled maintenance shutdowns.

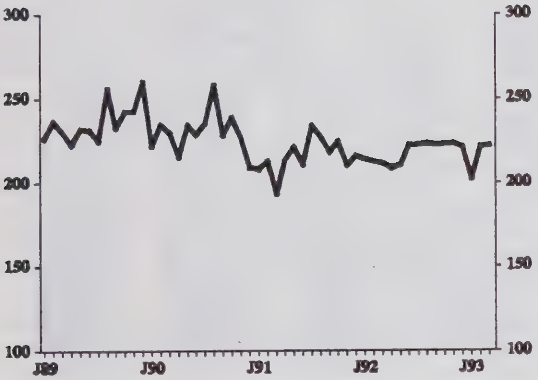
In keeping with a gradual downward trend over the last decade, refined petroleum product stocks at the end of the first quarter were down 7% from a year earlier to 10.2 million m^3. Most of the drop in product inventories occurred in Ontario, reflecting a particularly sluggish market for refined products in that region.

On the other hand, crude oil inventories were up 9%, to 2.6 million m^3, well within normal operating levels. Most of the increase was in the Prairies and Quebec where inventories rose by 15% and 8%, respectively.

1. Refined Petroleum Product Consumption

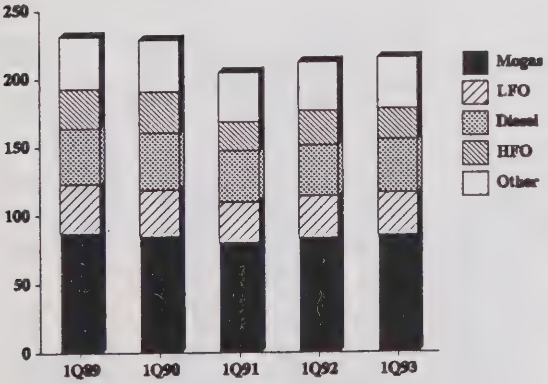
Demand for refined petroleum products in Canada remained relatively weak during the first quarter of 1993, having risen 1%, from 213 000 m^3/d to 216 000 m^3/d year over year. Product sales have essentially been flat over the last two years and remain some 15 000 m^3/d lower than pre-recession levels.

Figure 1.1
Total Product Sales
000 m^3/d



Heavy fuel oil (HFO) sales dropped by almost 4 000 m^3/d to 22 000 m^3/d, reflecting a 17% drop in the Atlantic region where there was a decline in electrical power generation. As a result of this winter's colder weather, heating oil sales went up 3% to 32 200 m^3/d. A rise in drilling rig activity in the Prairies helped to push diesel sales up 5% to 39 500 m^3/d.

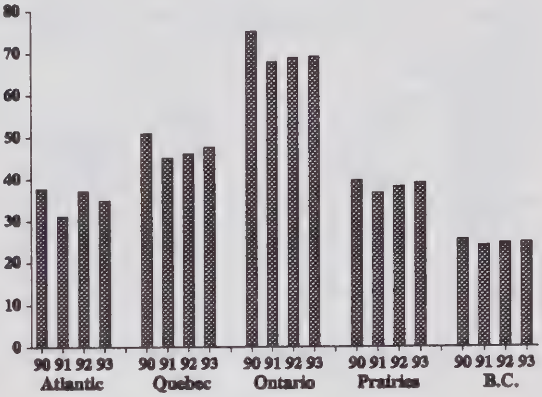
Figure 1.2
Product Sales by Product
000 m^3/d



There were also marginal increases in the demand for motor gasoline and "other" products with sales of 86 000 m^3/d and 38 000 m^3/d, respectively.

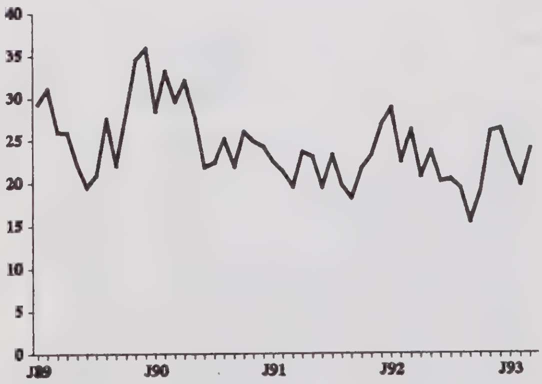
An increase in consumption in central and western Canada more than offset a drop in consumption in the Atlantic provinces. HFO accounted for most of the regional variation in product consumption.

Figure 1.3
Product Sales by Region
(First Quarter)
000 m^3/d



Heavy fuel oil sales have averaged about 22 000 m^3/d during the last two years. After peaking in 1989-1990, sales of HFO have been on the decline, mainly because of reduced use in electrical power generation and the manufacturing sector.

Figure 1.4
Heavy Fuel Oil Sales
000 m^3/d



2. Drilling and Exploration Activity

The drilling rig utilization rate in western Canada reached 65% during the first quarter of 1993, double the dismal rate recorded a year earlier. Total well completions jumped 37% to 1675 including a 62% increase in successful oil wells and a 49% increase in gas wells. This represents the highest level of activity since 1988.

A rise in development well completions accounted for most of the increase in drilling activity. Total completions at 1110 wells were up 65 % from a year earlier. Of this number, successful oil completions, linked to Alberta's royalty relief package, jumped 65% with drillers for the most part concentrating on shallow oil wells.

Figure 2.1
Drilling Activity in Western Canada
(Number of Wells)

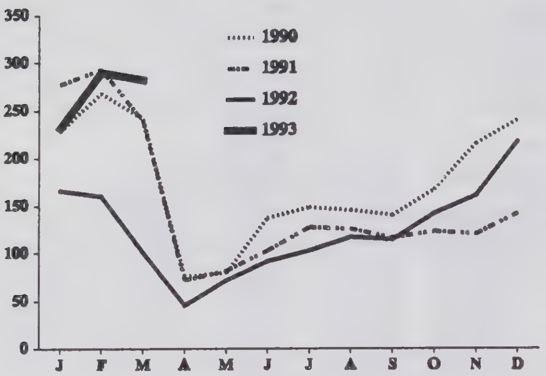
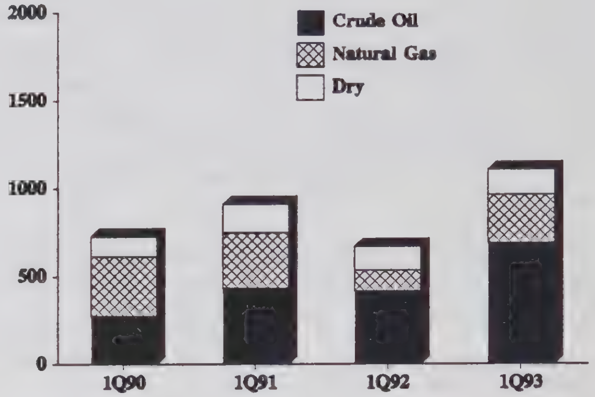


Figure 2.3
Development Well Completions
(Number of Wells)



The rig utilization rate in Alberta recovered from 33% to 70%. Most of this increase can be attributed to Alberta's October 1992 crude oil royalty relief package combined with a number of other factors such as relatively stable energy prices, rising investor interest, a lower Canadian dollar relative to the U.S. dollar and low interest rates. Drilling in Saskatchewan increased from 36% to 70% while in British Columbia activity increased from 33% to 58%.

Exploration activity took a back seat to development drilling. Total completions at 565 were up marginally from a year earlier. A 48% increase in successful oil exploration wells activity helped to offset a 13% decline in natural gas exploration.

Figure 2.2
Drilling Activity by Province
(Number of Wells)

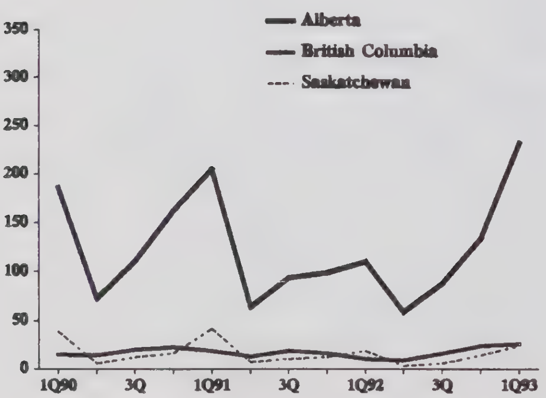
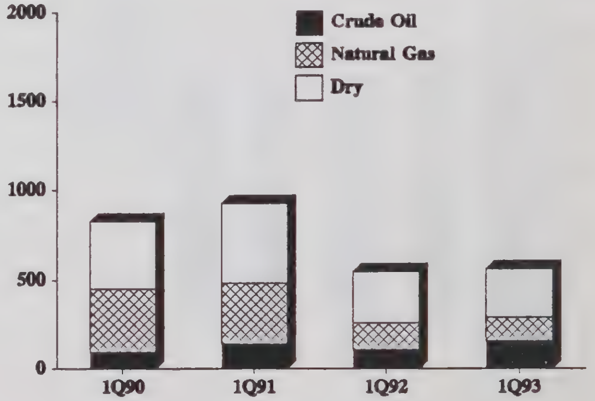


Figure 2.4
Exploratory Well Completions
(Number of Wells)

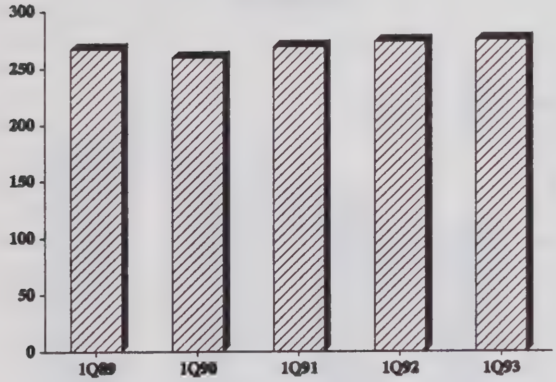


3. Crude Oil Supply

3.1 Domestic Production

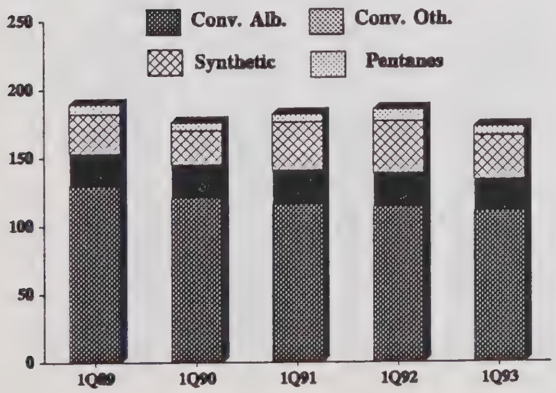
Production during the first quarter of 1993 averaged 276 000 m^3/d, marginally higher than a year earlier and some 15 000 m^3/d above the level recorded in the first quarter of 1990. Increases in heavy crude oil have more than compensated for falling, albeit at a slower rate than expected, conventional light crude production.

Figure 3.1.1
Crude Oil Production
000 m^3/d



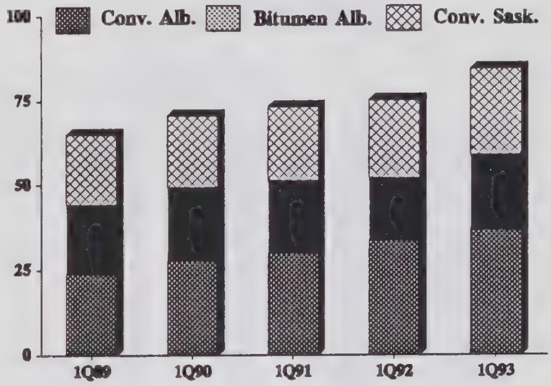
Light crude production dropped by 9 000 m^3/d to 175 000 m^3/d, year over year. A drop in Alberta conventional light and synthetic crude production explains most of the decline. Alberta conventional light crude declined by 3% to 110 000 m^3/d. Synthetic crude dropped 15% to 32 000 m^3/d due to a prolonged maintenance turnaround at the Syncrude oil sands plant in February and March.

Figure 3.1.2
Light Crude Oil Production
(Excluding diluent)
000 m^3/d



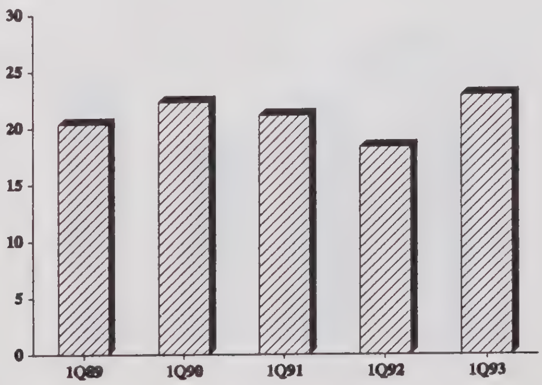
Blended heavy crude production grew to 101 000 m^3/d from 90 000 m^3/d, year over year. Production increased in both Alberta and Saskatchewan. Alberta accounted for about 70% of the increase, with production reaching 72 000 m^3/d, an increase of 8 000 m^3/d or 12%, from last year. Bitumen production rose by 15%, to 21 000 m^3/d. In Saskatchewan, production increased by 3 000 m^3/d to 29 000 m^3/d.

Figure 3.1.3
Heavy Crude Production
(Excluding diluent)
000 m^3/d



Bitumen accounted for a disproportionate share of the increase in Alberta heavy crude oil output. Bitumen production has benefited indirectly by greater demand for heavy oil following the start-up last year of both Conoco's coker facility at its Montana refinery, and the Lloydminster Bi-provincial upgrader.

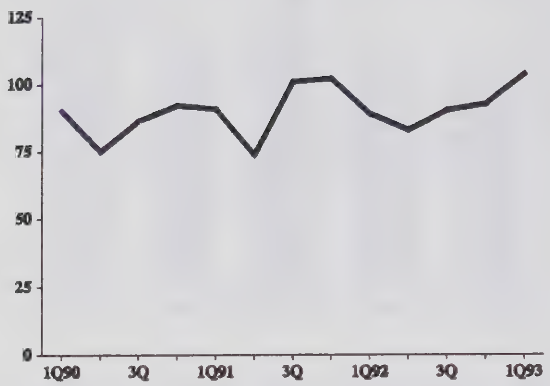
Figure 3.1.4
Bitumen Production
000 m^3/d



3.2. Crude Oil Imports

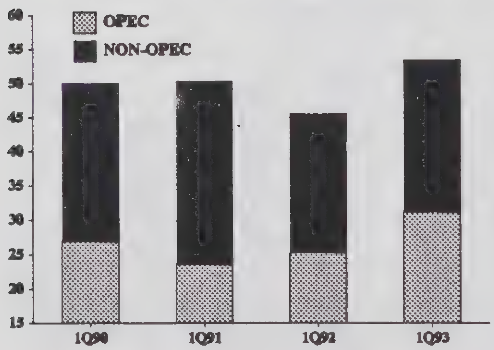
Total imports averaged 104 000 m^3/d in the first quarter of 1993, 15 000 m^3/d above a year earlier. The increase in imports is attributable in part to the temporary closure of the Sarnia-Montreal pipeline during the last two years which led to a rise in imports from the North Sea and Mexico into Quebec. As well, another Atlantic refiner has entered a processing agreement which involves refining of foreign crude with the refined products mainly destined for markets the in United States.

Figure 3.2.1
Total Crude Oil Imports
000 m^3/d



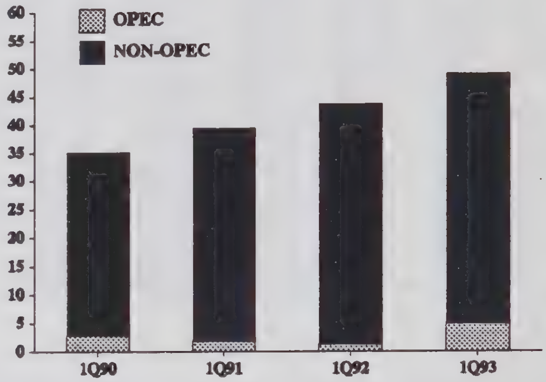
With the exception of a shipment of Canadian crude purchased in the U.S. Gulf, foreign crudes represented 98% of Atlantic refineries total feedstock requirements. Imports have generally been on the rise since the mid-1980s, reaching 55 000 m^3/d during the first quarter of 1993. OPEC crudes are becoming increasingly more important to refiners in that region.

Figure 3.2.2
Atlantic Crude Oil Imports
000 m^3/d



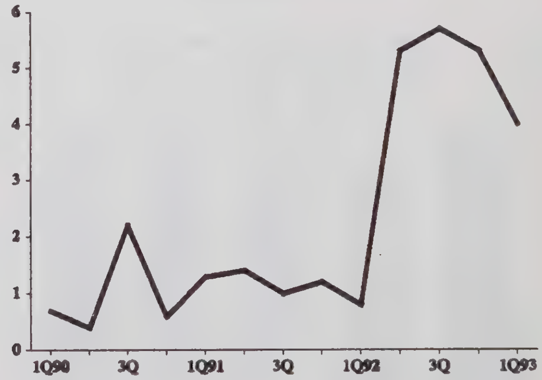
During the first quarter of 1993, Quebec imported 100% of its crude oil requirements. Crude oil imports averaged 50 000 m^3/d. Quebec relied predominantly on non-OPEC crude oil, with North Sea crudes from the U.K. and Norway accounting for 81% of its import receipts.

Figure 3.2.3
Quebec Imports
000 m^3/d



Imports of heavy crude from Mexico jumped from 1 000 m^3/d to 4 000 m^3/d between 1992 and 1993. The sharp increase resulted in large part from the unavailability of domestic heavy crude since the Sarnia- Montreal pipeline was closed in mid-1991.

Figure 3.2.4
Imports from Mexico
000 m^3/d

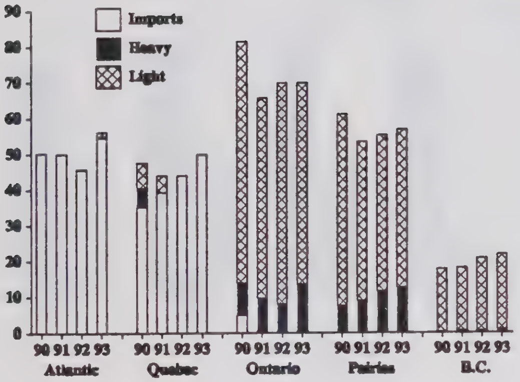


4 Crude Oil Disposition

4.1 Domestic Refinery Receipts

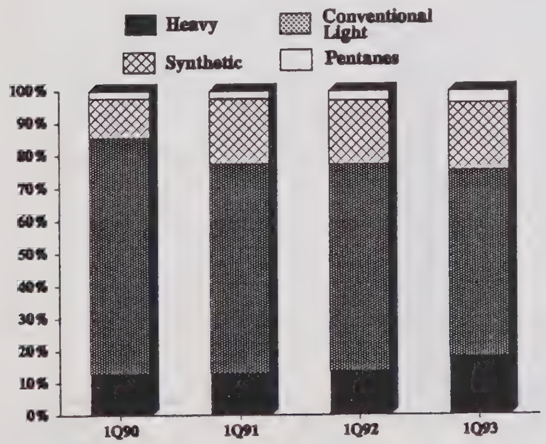
First quarter domestic refinery receipts of crude oil (excluding partially processed feedstock) averaged 253 000 m^3/d, up 20 000 m^3/d from a year earlier. Major increases in receipts occurred in the Atlantic region and Quebec. Both regions felt the impact of additional processing activity in the Atlantic region.

Figure 4.1
Domestic Refinery Receipts
(First Quarter)
000 m^3/d



The share of domestic conventional light crude oil receipts fell from 73% in 1990 to 58% in 1993. Receipts of heavy crude, synthetic and pentanes plus increased to 18%, 21% and 4% respectively in the first quarter of 1993.

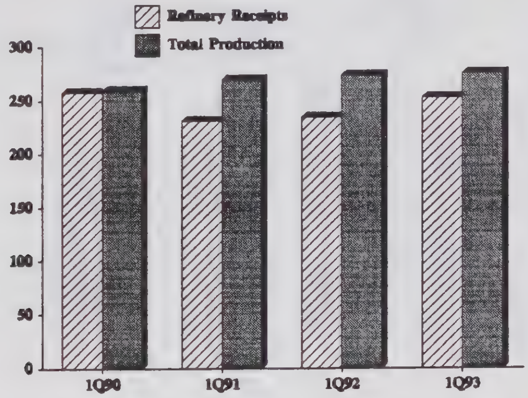
Figure 4.1.2
Domestic Receipts by Type of Crude Oil
Percentage Share



As per the following figure, the gap between domestic production and refinery receipts approximates the volume of Canadian net exports of crude oil. Canada is a net exporter of crude oil, in part because domestic refineries cannot process all of the heavier crudes produced in Canada.

Canadian refineries can refine only limited volumes of heavy crude oil, being equiped primarily to process light crude oil. As a result Canada is a net importer of light crude oil and a net exporter of heavy crude oil.

Figure 4.1.3
Production vs Refiner Receipts
000 m^3/d



The output of light crude oil averaged 175 000 $^3/d$ during the first quarter of 1993 while refinery demand (including imports) averaged about 213 000 m^3/d. On the other hand, heavy crude oil receipts approached 40 000 m^3/d while production (including diluent) averaged 101 000 m^3/d.

4.2. Crude Oil Exports

Crude oil exports remained virtually unchanged when compared to last year's first quarter, totalling 135 000 m^3/d. Light crude oil exports have accounted for all the increase in recent years, reflecting the drop in demand by domestic refiners caused by the recession and the closure of Sarnia-Montreal pipeline.

Since 1991, an increasing share of available supplies of light crude oil has been exported in contrast to heavy crude oil where the export share has declined. This reflects, in part, the closure of the Sarnia-Montreal pipeline in 1991, and the start-up of the Bi-provincial upgrader in Lloyminster late in 1992.

Figure 4.2.1
Crude Oil Exports
000 m^3/d

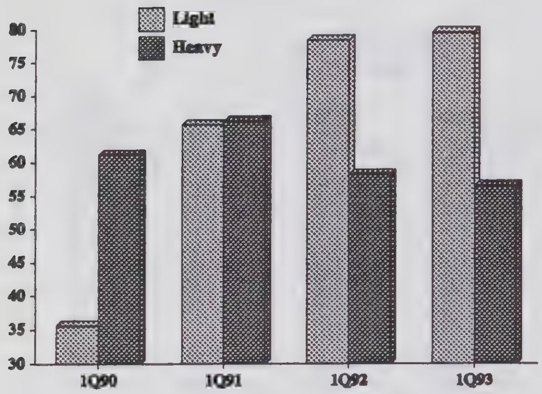
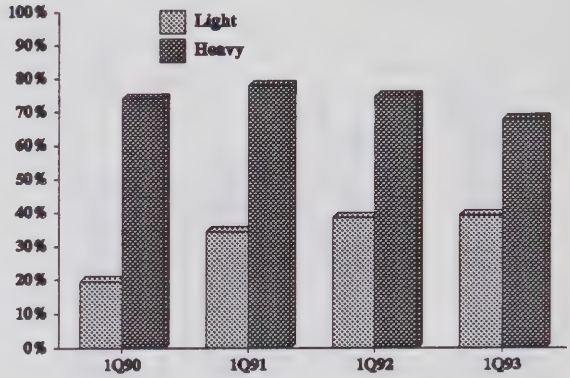


Figure 4.2.3
Ratio of Exports by Type of Crude
to Available Supply



Heavy crude exports have been affected by increased upgrading capacity in western Canada and some migration of heavy crude oil into light crude streams prior to entering the major pipelines for delivery to the refineries.

Typically, most Canadian crude oil exports have been delivered to U.S. refineries in the Great Lakes region (PADD II). In the first quarter of 1993, exports to PADD II reached 99 000 m^3/d. The sudden increase in exports to PADD V in 1993 likely reflects apportionment on the IPL system.

Figure 4.2.2
Crude Oil Exports
Percentage

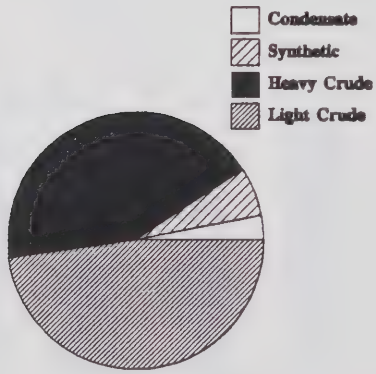
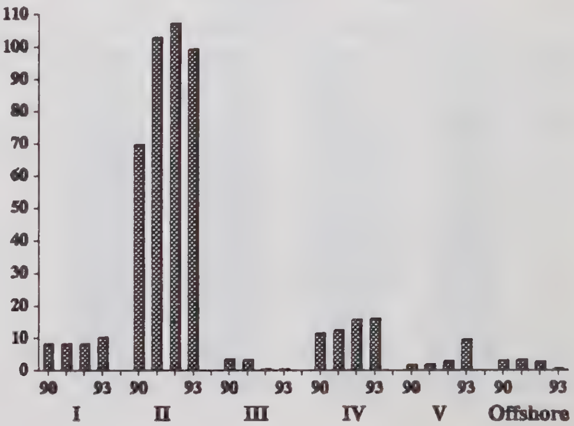


Figure 4.2.4
Crude Oil Exports by PADD
(First Quarter)
000 m^3/d



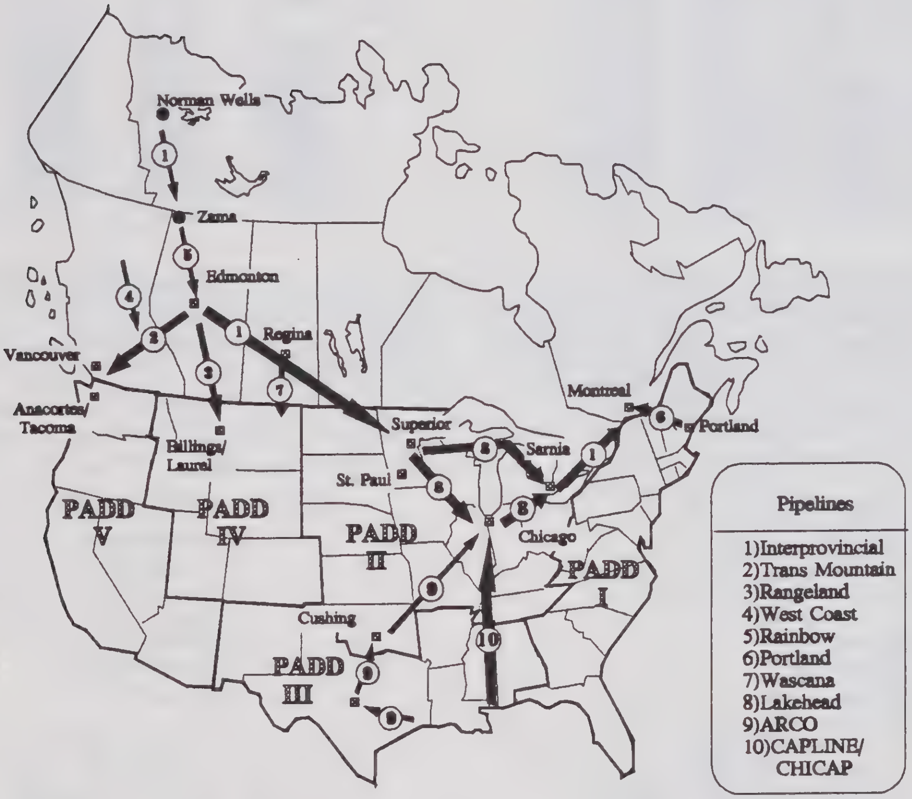
5. Pipeline Deliveries

Most Canadian crude oil is gathered at Edmonton, Alberta. It is then delivered to the domestic and export market, for the most part, by a network of pipelines.

The bulk of Canadian crude oil exports are delivered east into the United States via the Interprovincial and Lakehead pipeline systems. Smaller volumes are delivered by the Trans Mountain Pipe Line to the west coast for delivery to large U.S. refineries in the Puget Sound area and for tankering offshore. The Rangeland pipeline carries crude oil south into Montana.

Canadian crude oil delivered to the U.S. midwest competes in the key Chicago refining area with U.S. domestic crudes and other foreign crudes delivered through the CAPLINE/CHICAP pipeline system from the Louisiana Gulf Coast and, alternatively, the ARCO pipeline system from the Texas Gulf Coast via Cushing, Oklahoma.

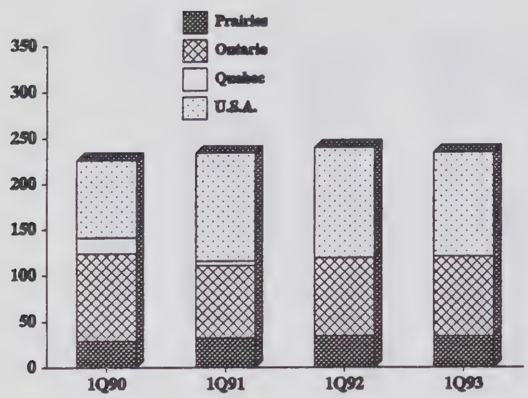
Figure 5
Major Crude Oil Pipelines



5.1 Interprovincial Pipe Line Deliveries (IPL)

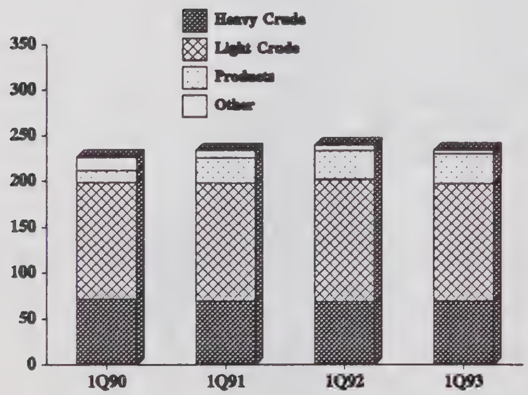
First quarter 1993 deliveries averaged 234 000 m^3/d about 2% or 6 000 m^3/d below a year earlier. Demand for pipeline space has exceeded capacity since October 1990. Apportionment during the first quarter averaged 20% reaching a high of 26% in January.

Figure 5.1.1
Deliveries by Destination
000 m^3/d



To alleviate the capacity shortfall and meet company supply forecasts, IPL, after considering a number of options, will formally apply to the National Energy Board for permission to increase capacity by about 18 000 m^3/d from Edmonton to Gretna, at an estimated cost of $258 million.

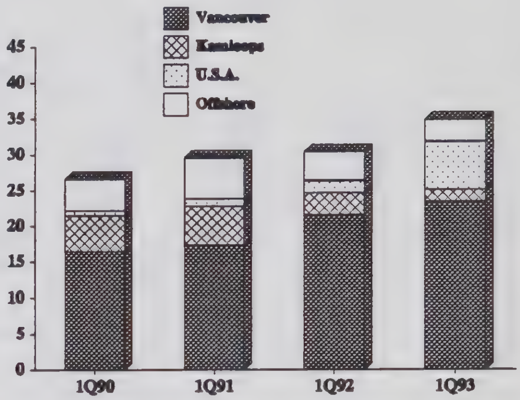
Figure 5.1.2
Deliveries by Type
000 m^3/d



5.2 Trans Mountain Pipe Line Deliveries (TMPL)

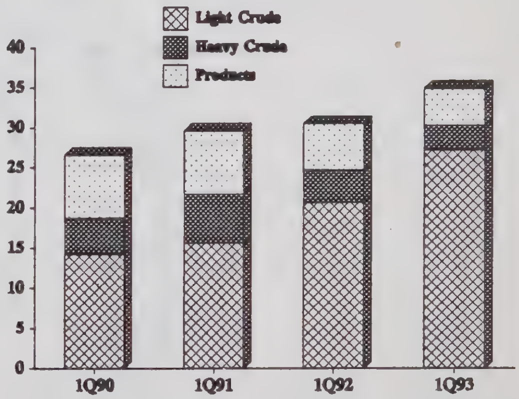
TMPL deliveries during the first quarter averaged 35 000 m^3/d, up about 5 000 m^3/d from a year earlier. Most of this increase was the result of high apportionment on the IPL system which resulted in a jump in TMPL deliveries of light crude oil to Washington State refineries.

Figure 5.2.1
Deliveries by Destination
000 m^3/d



Light crude oil deliveries represented about 78% of throughput compared to 53% in 1989. Heavy crude deliveries as a result of higher domestic demand declined from 17% to about 8%.

Figure 5.2.2
Deliveries by Type
000 m^3/d



6. Refinery Throughput and Utilization

Refinery throughput increased 3% compared to last year, from 253 000 m^3/d to 262 000 m^3/d. This resulted in a four percentage point increase in the national rate of refinery utilization, to 82% from 78%.

Despite the slight decline, the highest refinery utilization rate was still recorded in British Columbia, where it approached 95%. Ontario refiners had the lowest rate of utilization at 75%. Lower rates of activity in Ontario can be attributed to a cut in crude runs because of soft product prices and the impact of scheduled refinery maintenance shutdowns. In tandem with rising throughput, utilization increased in the Atlantic region, Quebec and the Prairies.

Figure 6.1
Refinery Throughput in Canada
000 m^3/d

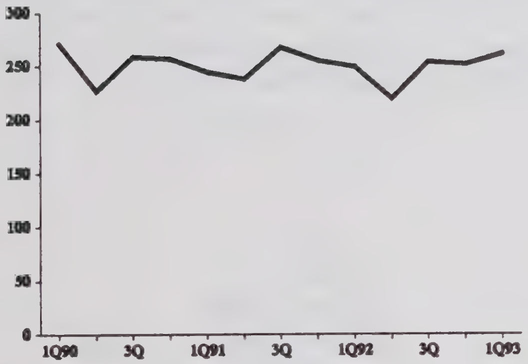
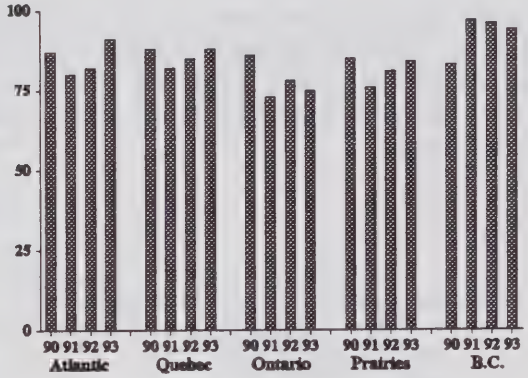


Figure 6.3
Refinery Utilization Rate by Region
Percentage



Most of the increase in refinery throughput occurred in Atlantic Canada where crude runs rose from 48 000 m^3/d to 56 000 m^3/d. Despite operational problems at the Montreal refineries, refinery throughput nevertheless increased in Quebec, from 45 000 m^3/d to 47 000 m^3/d. Refineries in the Prairies also recorded higher throughput, with crude runs up by 3 000 m^3/d to 60 000 m^3/d. On the other hand, there were slight declines at Ontario and B.C. refineries

Since 1991, Canadian refiners have been able to partly offset the slump in domestic sales through higher sales in the export market. The stock builds typically observed in the first quarter occur because refiners build product inventories prior to scheduled turnarounds in the second quarter. However, there was no stock build in 1991 as refiners drew down inventories in response to the severity of the downturn in product demand at that time.

Figure 6.2
Refinery Throughput by Region
(First Quarter)
000 m^3/d

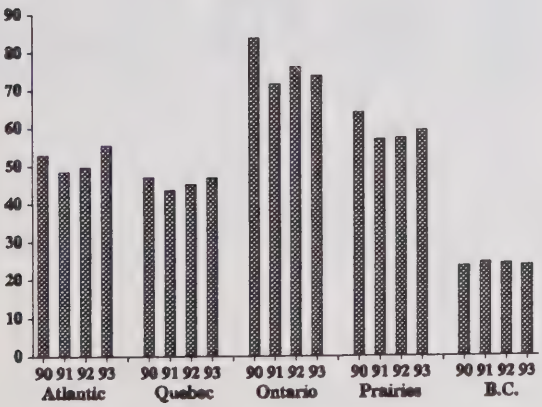
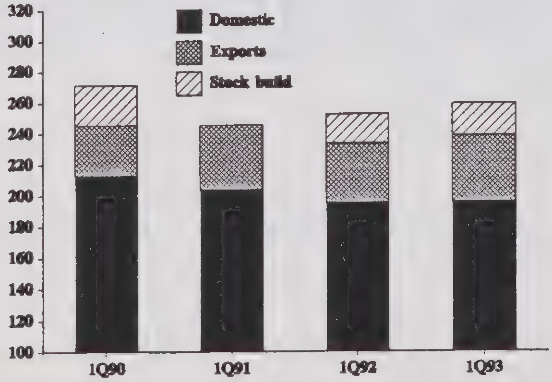


Figure 6.4
Refinery Production by Market
000 m^3/d



7. Crude Oil and Petroleum Product Stocks

Primary stocks of crude oil and refined petroleum products closed the first quarter of 1993 at 12.8 million m^3. Stocks were down 4% or 499 000 m^3 from that recorded a year earlier.

Of this volume, refined petroleum product stocks at about 10.2 million m^3 were down 7% or 719 000 m^3 from a year earlier. This decrease represented a product drawdown of about 2 000 m^3/d over the year before. Crude oil stocks were up 9% to 2.6 million m^3, well within normal operating levels.

Petroleum product stocks were down in the Atlantic region (10%), Ontario (15%) and Prairies (8%). Quebec and British Columbia recorded modest increases of 4% and 7% respectively. All regions recorded a rise in crude oil stocks except in the Prairies.

Stocks of 'main' petroleum products at 6.6 million m^3 were down 9% or 631 000 m^3. This was led by a 17% drop in motor gasoline to 3.2 million m^3. Stocks of middle distillates including light fuels and diesel were up slighty at 2.7 million m^3. Heavy fuel oil held at 700 000 m^3.

End-of-March crude oil and refined petroleum product stocks* represented a reserve of 60 days of supply. This compares with 61 days of supply a year earlier. Main petroleum product stocks fell to 38 days from 42 days.

Note:
Stocks do not include estimates of crude oil held in pipelines tankage. If these stocks were to be included in the calculation, it is estimated that the number of days of supply would increase by about 7 days.

Figure 7.1
Crude Oil and Petroleum Product Stocks
(End of Quarter)
million m^3

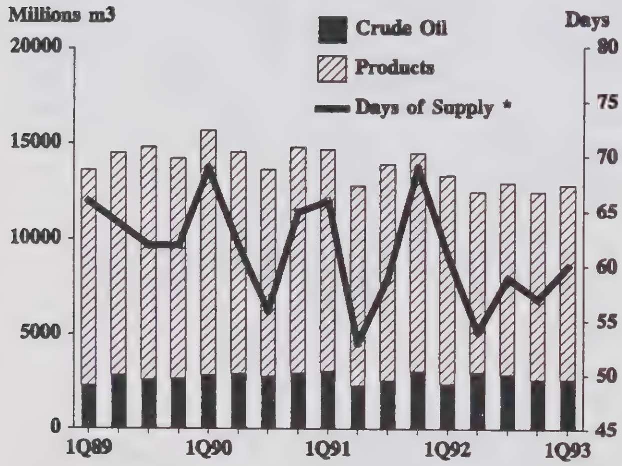


Figure 7.2
Stocks by Region
(End of Quarter)
million m^3

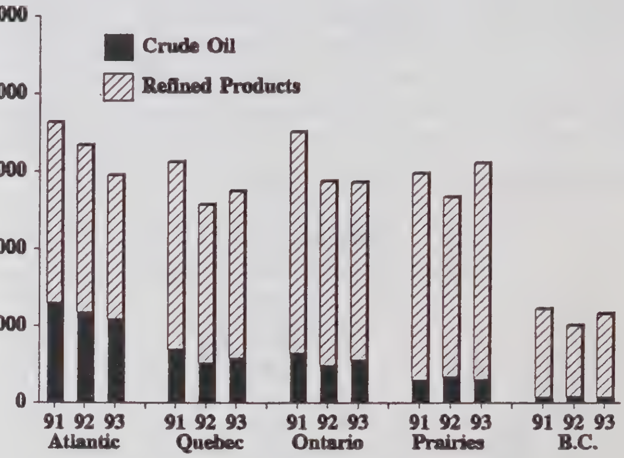


Figure 7.3
Total Petroleum Product Stocks
thousands of m³

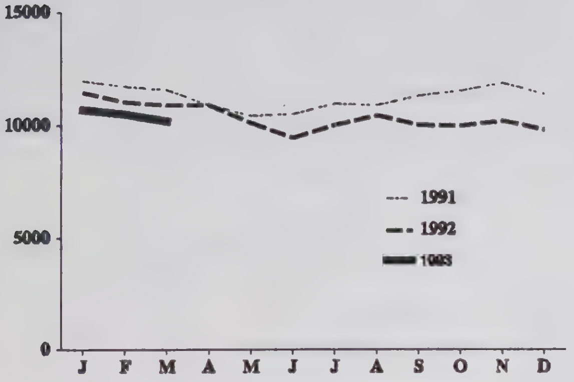


Figure 7.4
Motor Gasoline Stocks
thousands of m³

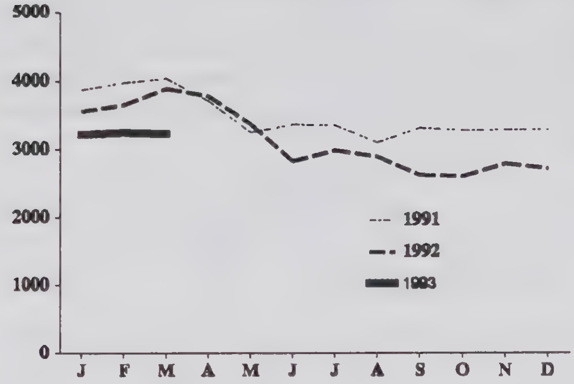


Figure 7.5
Light Fuel Oil Stocks
thousands m³

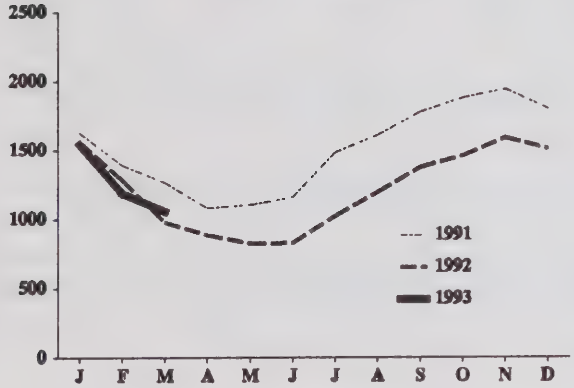


Figure 7.6
Diesel Fuel Oil Stocks
thousands m³

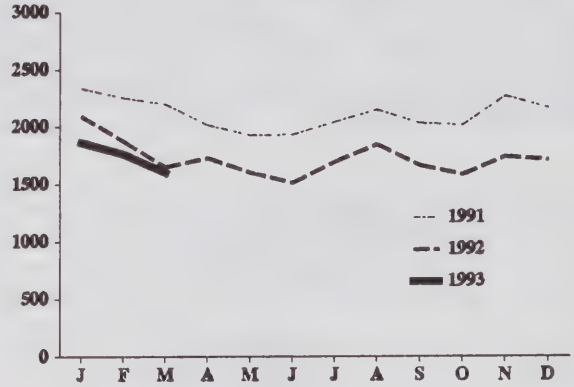


Figure 7.7
Heavy Fuel Oil Stocks
thousands m³

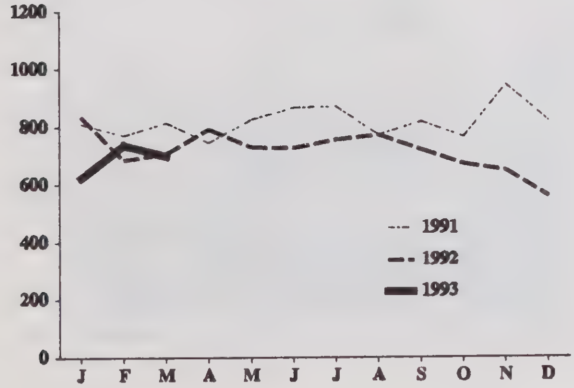
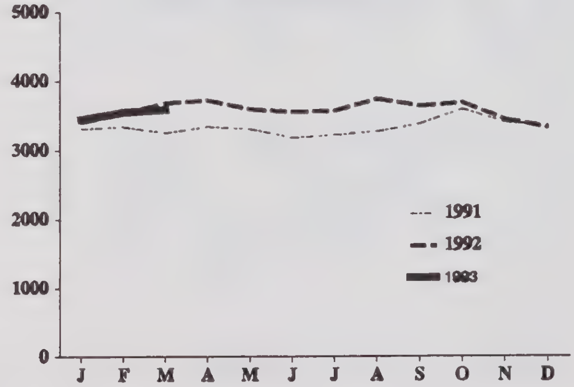


Figure 7.8
Other Petroleum Product Stocks
thousands m³



8. Crude Oil Prices

8.1 International Price Developments

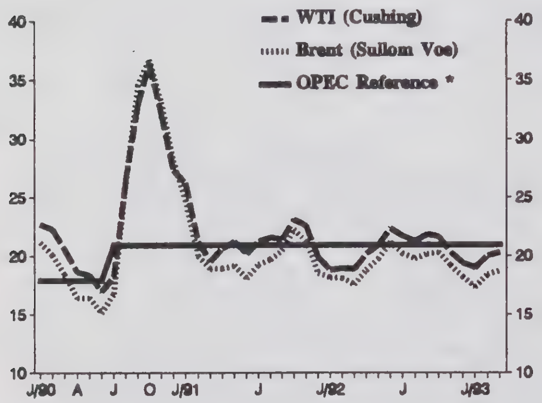
Canadian crude oil prices are typically affected by international supply and demand fundamentals and to a lesser extent local market conditions in the United States and Canada.

World oil markets were well-supplied during the first quarter of 1993 with unexpectedly strong exports from the Former Soviet Union and continuing high OPEC crude production.

Spot crude prices traded in a very narrow band with the price of West Texas Intermediate (WTI), the U.S. benchmark crude, trading between US$18.70 and US$20.65. Spot crude prices averaged US$19.80/bbl during the quarter, up $1.10/bbl from a year earlier.

World oil prices continued to be dampened by sluggish demand for crude oil due to the slow recovery in the American and Canadian economies, the slowdown in the Japanese economy and the recession in some large European countries such as Germany.

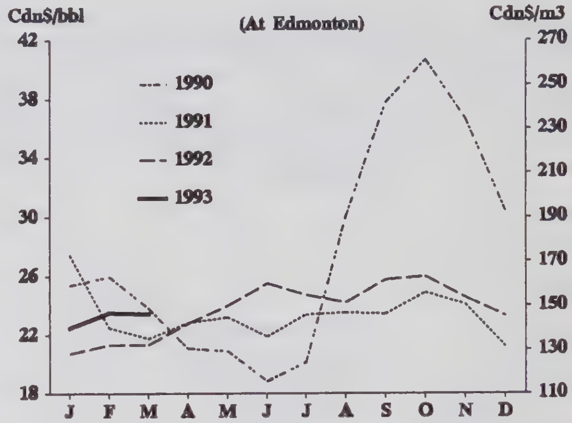
Figure 8.1
International Crude Oil Prices
US$/barrel



8.2 Domestic Crude Oil Postings

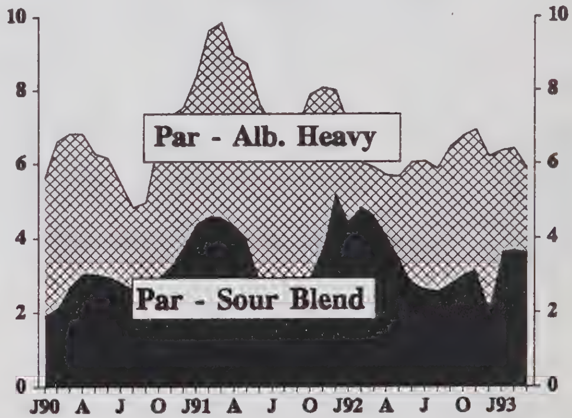
The first quarter 1993 price of Canadian Par crude (40°API, 0.5 % sulphur), as posted by four Canadian refiners, averaged $22.96/bbl ($144.48/m^3). Although the first quarter price averaged $2.16/bbl above a year earlier the price slipped $1.54/bbl below the previous quarter. In fact, prices have been under steady downward pressure since October 1992.

Figure 8.2.1
Canadian Par Crude Oil Postings



The following figure illustrates the differential between the price of Canadian Par crude at Edmonton and the price of Alberta heavy crude posted at Hardisty. Par is also compared to Alberta light sour blend.

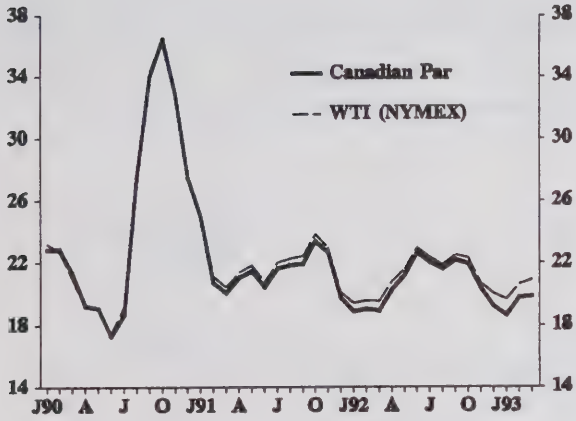
Figure 8.2.2
Crude Oil Price Differentials
(CDN$/bbl)



8.3 Light Crude Oil Prices at Chicago

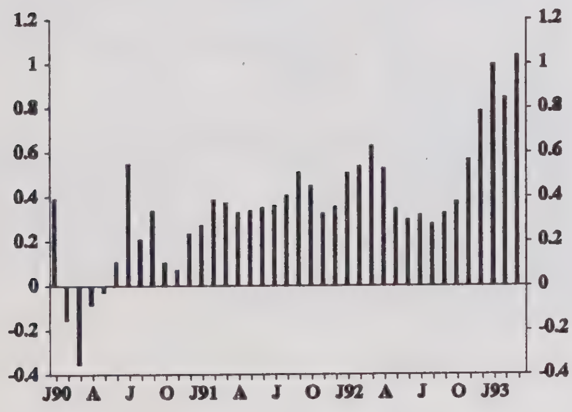
The following graphs compare the price of Canadian Par crude oil to the comparable WTI (NYMEX), U.S. benchmark crude (40°API), delivered to Chicago.

Figure 8.3.1
Light Crude Oil Prices at Chicago
(US$/bbl)



Over the first quarter, WTI traded almost US$1.00/bbl above Par compared with US$0.56/bbl a year earlier. The widening differential is attributed to weak demand and delivery problems associated with apportionment on the IPL system.

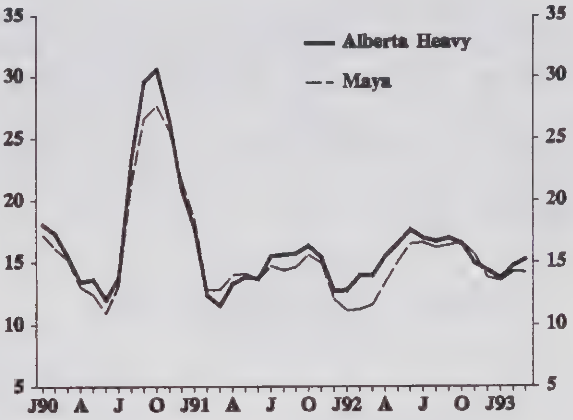
Figure 8.3.2
WTI/Canadian Par Differential
(US$/bbl)



8.4 Heavy Crude Oil Prices at Chicago

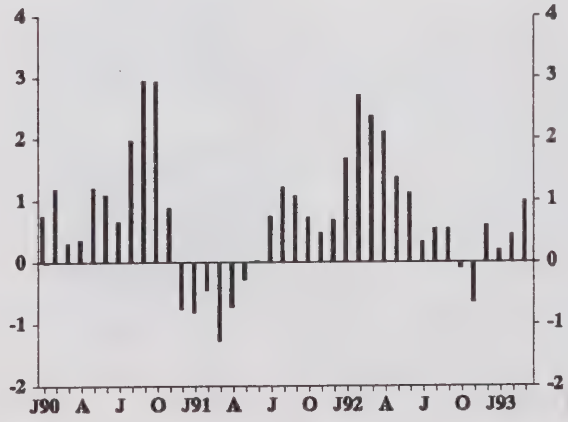
The following graphs compare the price of Alberta heavy crude oil (25.2° API) to Mexican Maya (22.5°API), delivered to Chicago.

Figure 8.4.1
Heavy Crude Oil Prices at Chicago
(US$/bbl)



Alberta heavy crude has been generally more expensive than Maya. However, aside from the impact of seasonal swings in demand, the differential has narrowed to about US$0.56/bbl despite higher domestic demand resulting from a rise in upgrading capacity.

Figure 8.4.2
Alberta Heavy/Maya
(US$/bbl)



9. Refined Petroleum Product Prices

During the first quarter of 1993, the price of regular unleaded gasoline at self-serve outlets averaged 53.8 cents/litre, a reduction of 1.3 cents/litre over the fourth quarter of 1992. While prices have been falling gradually since the end of last year, the bulk of the decrease took place in March when price wars in Regina and Calgary and continuing price volatility in Toronto contributed to a 1.2 cent/litre month-to-month decline.

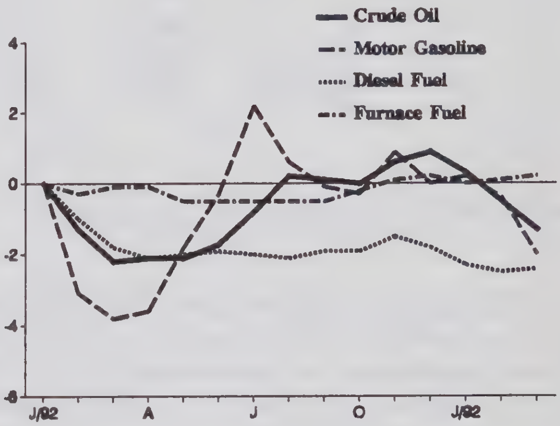
The average regular unleaded gasoline price during the first quarter of 1993 was the lowest since the fourth quarter of 1989, with the exception of the first quarter of 1992 when the price averaged 53.3 cents/litre. When the first quarter 1993 price is adjusted for inflation, it has declined 11% or 5.5 cents/litre over the five-year period beginning with the first quarter of 1988.

Figure 9.1
Regular Unleaded Gasoline Prices
(10 city average)

The first quarter 1993 average diesel price (52.4 cents/litre) was 0.6 cents/litre lower than the average price during the previous quarter, continuing a trend of declining diesel prices which began late in 1991. The first quarter 1993 reduction was largely due to the increasing competitiveness in the Halifax where diesel prices fell 4.6 cents/litre to 55.5 cents/litre in March 1993 from the average December 1992 price. Both gasoline and diesel prices have been falling in Halifax area since the July 1991 deregulation of petroleum product prices in that province. The elimination of most barriers to entry has resulted in a growth in the independents' share of retail gasoline sales from 3% to 7%.

The following graph indicates changes in crude oil and major petroleum product prices since January 1992. The crude oil prices are lagged two months to account for the estimated time it takes crude to be refined into petroleum products and distributed to the consumer. Since the end of 1992, there has been little movement in furnace fuel and diesel prices. The price of crude oil has fallen 2.2 cents/litre in response to international pressures. As mentioned previously, motor gasoline prices fell as competition heated up in some markets and demand fell off during the traditionally slow winter months.

Figure 9.2
Cumulative Price Changes Since January 1992



Consumption Taxes on Petroleum Products

At the end of the first quarter 1993, the federal taxes (Goods & Services Tax (GST) and Excise Tax) and provincial taxes on regular unleaded gasoline averaged 25.8 cents/litre, a 0.1 cent/litre reduction from the average tax at the end of December 1992. Lower gasoline prices resulted in the average GST falling 0.1 cent/litre.

In Nova Scotia, their quarterly review resulted in a 0.9 cent/litre gasoline tax reduction in response to falling gasoline prices in that province. The effect of this tax reduction on the average provincial tax was offset by Saskatchewan's 2 cent/litre provincial tax increase which was introduced in their March 1993 budget.

Canada vs United States

The average price of motor gasoline declined 2 cents/litre in both Canada and the United States between December 1992 and March 1993 from 56.2 and 40.3 cents/litre, respectively. As the price reductions were the same, the price spread between the two countries remained 15.9 cents/litre, more than 90% of which continues to be attributable to higher taxes in Canada. The rest of the differential is due to larger downstream margins in Canada, resulting from significant structural differences between the two markets. For example, economies of scale in the form of substantially higher volume per unit of investment favour American marketers and refiners.

Figure 9.3
Average Retail Price of Motor Gasoline
(Canada vs U.S.A)
cents/litre

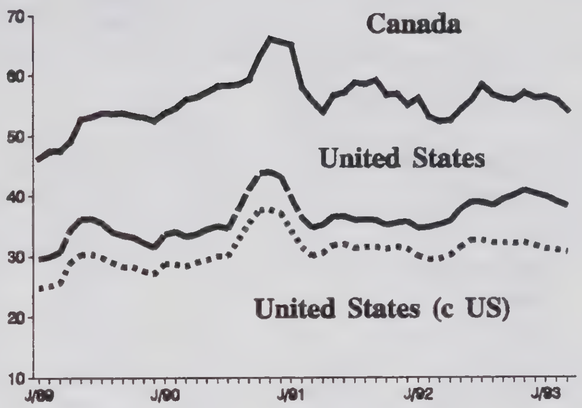
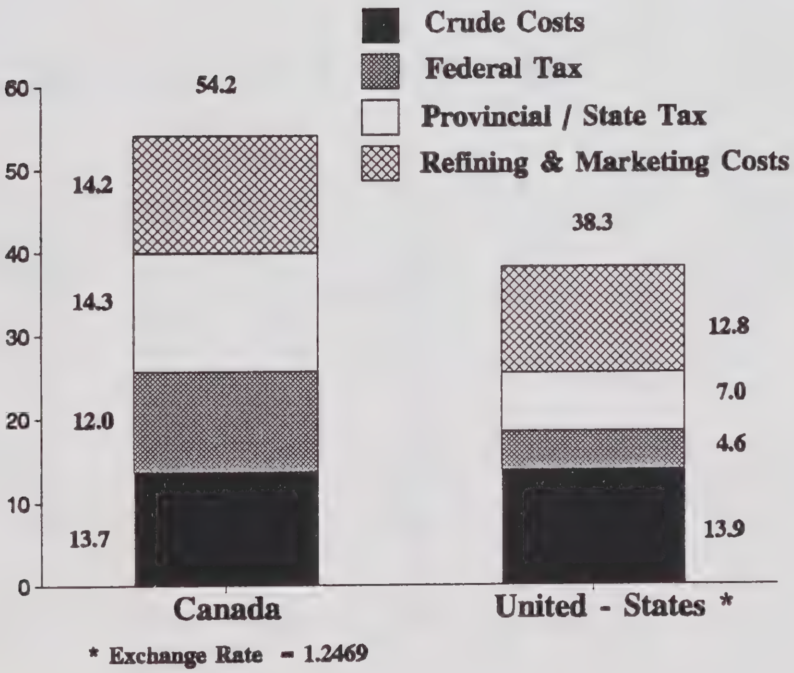


Figure 9.4
Breakdown of Average Pump Price
(March 1993)
cents/litre



Appendix I
Production of Crude Oil and Equivalent
(000 m^3/d)

	1991 Year	1Q	2Q	3Q	4Q	1992 Year	1993 1Q
A. Light and Equivalent							
Conventional							
Alberta	112.2	113.6	108.5	110.4	106.1	109.7	109.7
B.C.	5.5	5.5	5.5	5.5	5.6	5.6	5.5
Saskatchewan	11.4	11.4	11.4	11.6	12.2	11.7	12.2
Manitoba	1.9	1.8	1.8	1.7	1.8	1.8	1.7
NWT	5.2	5.3	5.2	5.6	4.4	5.2	4.7
Ontario	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Nova Scotia	-	-	0.7	3.5	2.2	1.7	0.0
Total	**137.3**	**138.2**	**133.7**	**138.9**	**132.9**	**136.3**	**134.4**
Synthetic							
Suncor	9.1	10.2	6.4	9.8	9.2	8.9	9.0
Syncrude	29.6	27.6	26.4	27.2	32.0	28.3	23.0
Total	**38.7**	**37.8**	**32.8**	**37.0**	**41.2**	**37.2**	**32.0**
Pentanes Plus(excl. diluent)	**9.0**	**8.0**	**6.2**	**7.6**	**8.6**	**7.6**	**8.5**
Total Light	**185.0**	**184.0**	**172.7**	**183.5**	**182.7**	**181.1**	**174.9**
B. Heavy Crude							
Alberta							
Conventional	32.1	34.5	33.6	36.2	38.3	35.7	39.9
Bitumen	16.5	18.4	20.7	21.8	18.5	19.9	20.5
Diluent	8.6	10.7	10.6	10.3	10.6	10.6	11.7
Total	**57.2**	**63.6**	**64.9**	**68.3**	**67.4**	**66.2**	**72.1**
Saskatchewan							
Conventional	23.4	23.4	24.0	25.3	25.8	24.7	25.8
Diluent	3.3	3.4	3.3	3.1	3.6	3.4	3.5
Total	**26.7**	**26.8**	**27.3**	**28.4**	**29.4**	**28.1**	**29.3**
Total Heavy	**83.9**	**90.4**	**92.2**	**96.7**	**96.8**	**94.3**	**101.4**
C. Total Production	**268.9**	**274.4**	**264.9**	**280.2**	**279.5**	**275.4**	**276.3**

Appendix II
Supply and Disposition of Crude Oil and Equivalent
(000 m^3/d)

	1991 Year	1Q	2Q	3Q	4Q	1992 Year	1993 1Q
A. Light and Equivalent							
Supply							
Production	179.4	184.0	172.7	183.5	182.7	181.1	174.9
Plus: Upgraders	2.0	3.4	0.7	4.4	10.2	4.7	9.6
Statistical Diff.	8.1	13.3	12.7	14.2	9.1	12.3	14.6
Net Supply	189.5	202.7	186.1	202.1	202.0	198.1	199.1
Domestic Demand							
Atlantic	0	0	0	0	2.1	0.6	1.8
Quebec	2.7	0	0	1.4	0	0.4	0.0
Ontario	58.8	61.3	51.0	58.5	60.4	57.9	55.9
Prairies	46.6	43.2	40.5	46.5	42.4	43.2	43.6
B.C.	18.9	20.0	21.2	21.4	19.7	20.6	20.0
Total	127.0	124.4	112.7	127.8	124.6	122.4	121.3
Exports	**62.4**	**78.3**	**73.4**	**74.3**	**77.4**	**75.7**	**77.8**
Total Demand	**189.4**	**202.7**	**186.1**	**202.1**	**202.0**	**198.1**	**199.1**
B. Heavy Crude (Blended)							
Supply							
Production	84.7	90.4	92.2	96.7	96.8	94.3	101.4
Recycled Diluent	1.0	0.9	1.0	2.1	1.0	1.3	2.3
Less: Upgrader Feedstock	0	0	1.6	2.4	4.0	2.1	7.0
Statistical Diff.	(5.0)	(13.6)	(15.7)	(8.7)	(16.7)	(13.9)	(12.7)
Net Supply	80.7	77.7	75.9	87.7	77.1	79.6	84.0
Domestic Demand							
Atlantic	0	0	0	0	0	0	0
Quebec	0.1	0	0	0	0	0	0
Ontario	10.2	7.7	11.2	11.6	7.9	9.6	13.4
Prairies	10.3	11.4	8.9	13.9	10.6	11.2	12.6
B.C.	0.6	0.6	0.5	0.9	1.0	0.8	0.9
Total	21.1	19.6	20.6	26.3	19.5	21.5	26.9
Exports	**59.6**	**58.1**	**55.3**	**61.4**	**57.6**	**58.1**	**57.1**
Total Demand	**80.7**	**77.7**	**75.9**	**87.7**	**77.1**	**79.6**	**84.0**

Appendix III
Crude Oil Exports by Destination
(000 m^3/d)

		1991 Year	1Q	2Q	3Q	4Q	1992 Year	1993 1Q
U.S. PAD Districts *								
I	Light	7.2	7.4	8.3	8.1	7.8	7.9	7.9
	Heavy	1.3	1.3	1.4	1.6	1.3	1.4	2.2
	Total	**8.5**	**8.7**	**9.7**	**9.7**	**9.1**	**9.3**	**10.1**
II	Light	41.9	53.6	51.6	48.7	41.8	50.9	49.9
	Heavy	51.8	53.5	48.6	54.4	51.3	52.0	49.3
	Total	**93.7**	**107.1**	**100.2**	**103.1**	**100.9**	**102.9**	**99.2**
III	Light	0	0	0	2.4	0.8	1.0	0
	Heavy	1.5	0	0	0	0	0	0
	Total	**1.5**	**0**	**0.8**	**2.4**	**0.8**	**1.0**	**0**
IV	Light	11.1	13.0	8.7	10.4	10.5	10.7	10.4
	Heavy	3.0	2.5	4.9	4.7	4.8	4.2	5.5
	Total	**14.1**	**15.5**	**13.6**	**15.1**	**15.3**	**14.9**	**15.9**
V	Light	1.3	2.5	2.9	3.1	6.0	3.5	9.3
	Heavy	0.5	0	0.5	0.7	0.2	0.3	0.1
	Total	**1.8**	**2.5**	**3.4**	**3.8**	**6.2**	**3.8**	**9.4**
Total U.S.	**Light**	**61.5**	**76.5**	**72.3**	**72.7**	**74.7**	**74.0**	**77.5**
	Heavy	**58.0**	**57.3**	**55.4**	**61.4**	**57.6**	**57.9**	**57.1**
	Total	**119.5**	**133.8**	**127.7**	**134.1**	**132.3**	**131.9**	**134.6**
Offshore	**Light**	**0.6**	**1.5**	**1.1**	**1.5**	**2.7**	**1.7**	**0.3**
	Heavy	**1.4**	**0.9**	**0**	**0**	**0**	**0.2**	**0**
	Total	**2.0**	**2.4**	**1.1**	**1.5**	**2.7**	**1.9**	**0.3**
Total	**Light**	**62.1**	**78.0**	**73.4**	**74.2**	**77.4**	**75.7**	**77.8**
	Heavy	**59.4**	**58.2**	**55.4**	**61.4**	**57.6**	**58.1**	**57.1**
	Total	**121.6**	**136.2**	**128.8**	**135.6**	**135.0**	**133.8**	**134.9**

** U.S. Petroleum Administration for Defense (PAD) Districts*

Appendix IV
Pipeline Deliveries
(000 m^3/d)

		1991 Year	1Q	2Q	3Q	4Q	1992 Year	1993 1Q
A.	**Trans Mountain Pipe Line (TMPL)**							
	Domestic Deliveries							
	Light Crude	16.8	19.0	21.1	20.2	20.6	20.2	20.4
	Heavy Crude	0.5	0	0.2	0.3	0.3	0.2	0
	Semi Refined Products	3.9	3.1	1.7	2.6	2.7	2.5	1.7
	Refined Products	2.5	2.7	2.4	2.8	2.7	2.6	3.0
	Total	**23.7**	**24.8**	**25.4**	**25.9**	**26.3**	**25.6**	**25.1**
	Foreign Deliveries							
	Tankers	4.0	4.0	4.6	2.3	4.2	3.8	3.1
	Puget Sound Area	1.1	1.7	2.2	3.0	4.4	2.8	6.7
	Total	**5.1**	**5.7**	**6.8**	**5.3**	**8.6**	**6.6**	**9.8**
	Total TMPL	**28.8**	**30.4**	**32.2**	**32.8**	**34.9**	**32.2**	**34.9**
B.	**Interprovincial Pipe Line (IPL)**							
	Domestic Deliveries							
	Light Crude	74.1	74.0	63.3	67.9	71.1	69.2	70.0
	Heavy Crude	13.8	13.6	15.4	17.8	13.2	15.0	18.3
	Other (1)	27.2	31.3	28.6	29.3	30.9	30.0	31.9
	Total	**115.1**	**118.9**	**107.3**	**115.0**	**115.2**	**114.2**	**120.2**
	Foreign Deliveries							
	Light Crude	49.5	59.5	58.0	56.7	57.9	58.0	57.6
	Heavy Crude	53.2	54.8	50.1	56.0	46.4	53.3	51.5
	Other (1)(2)	6.7	6.6	5.5	5.4	11.3	5.8	4.7
	Total	**109.4**	**120.9**	**113.6**	**118.1**	**115.6**	**117.1**	**113.8**
	Total IPL	**224.5**	**239.8**	**220.9**	**233.1**	**230.8**	**231.3**	**234.0**
C.	**Pipelines to Montreal**							
	IPL Deliveries							
	To Montreal	2.4	0	0	0	0	0	0
	For Export/Transfer	0	0	0	0	0	0	0
	Total IPL	**2.4**	**0**	**0**	**0**	**0**	**0**	**0**
	Portland-Montreal							
	Montreal Imports (3)	25.0	28.4	20.8	29.3	27.7	26.5	31.6
	Total Montreal Receipts	**27.4**	**28.4**	**20.8**	**29.3**	**27.7**	**26.5**	**31.6**

(1) includes petroleum products and NGL's. *(3) may include cargos imported directly into Montreal*
(2) includes some US domestic crudes delivered to the U.S.

Appendix V
Canadian Refinery Receipts
(000 m^3/d)

		1991 Year	1Q	2Q	3Q	4Q	1992 Year	1993 1Q
A.	**Domestic Receipts**							
	Light & Equivalent							
	Atlantic	0	0	0	0	2.1	0.5	1.3
	Quebec	0	0	0	1.4	0	0.4	0
	Ontario	58.9	61.3	51.0	58.4	60.4	57.8	56.3
	Prairies	46.7	43.2	40.5	46.6	42.4	43.2	44.2
	B.C.	18.8	19.9	21.2	21.4	19.7	20.6	20.9
	Total	**124.4**	**124.4**	**112.7**	**127.8**	**124.6**	**122.5**	**122.7**
	Heavy							
	Atlantic	0	0	0	0	0	0	0
	Quebec	0	0	0	0	0	0	0
	Ontario	10.2	7.7	11.2	11.6	7.8	9.6	13.3
	Prairies	10.2	11.4	8.9	13.8	10.6	11.2	12.6
	B.C.	0.6	0.6	0.5	0.9	1.0	0.8	0.9
	Total	**21.0**	**19.7**	**20.6**	**26.3**	**19.4**	**21.6**	**26.8**
	Other (incl. partially processed)							
	Atlantic	0.3	0	0	0	0	0	0
	Quebec	0.1	0	0	0	0	0	0
	Ontario	4.5	4.9	4.0	4.9	5.1	4.8	4.7
	Prairies	3.9	3.8	1.5	3.0	3.4	2.9	3.2
	B.C.	4.1	3.3	2.0	2.8	3.1	2.8	1.9
	Total	**12.9**	**12.0**	**7.5**	**10.7**	**11.6**	**10.5**	**9.8**
	Total Domestic Receipts							
	Atlantic	0.3	0	0	0	2.1	0.5	1.3
	Quebec	0.1	0	0	1.4	0	0.4	0
	Ontario	73.6	73.9	66.2	74.9	73.3	72.2	74.3
	Prairies	60.8	58.4	50.9	63.4	56.4	57.3	60.0
	B.C.	23.5	23.8	23.7	25.1	23.8	24.2	23.7
	Total	**158.3**	**156.1**	**140.8**	**164.8**	**155.6**	**154.6**	**159.3**
B.	**Crude Oil Imports**							
	Atlantic	49.7	45.2	42.3	43.8	46.3	44.4	54.7
	Quebec	41.9	43.5	39.7	46.1	45.9	43.8	48.6
	Ontario	0.4	0.2	0.9	0.2	0.4	0.5	0.3
	Prairies	0	0	0	0	0	0	0
	B.C.	0	0	0	0.1	0	0	0
	Total	**92.0**	**88 .9**	**83.0**	**90.1**	**92.6**	**88.7**	**103.6**
C.	**Total Receipts**							
	Atlantic	50.0	45.2	42.3	43.8	48.4	44.9	56.0
	Quebec	42.0	43.5	39.7	47.5	45.9	44.2	48.6
	Ontario	74.0	74.1	67.1	75.1	73.7	72.7	74.6
	Prairies	60.8	58.4	50.9	63.4	56.4	57.3	60.0
	B.C.	23.5	23.8	23.8	25.1	23.8	24.2	23.7
	Total	**250.3**	**245.1**	**223.8**	**254.9**	**248.2**	**243.3**	**262.9**

Appendix VI
International and Domestic Crude Oil Prices
(US$/bbl)

	At Source			At Chicago			At Montreal	
	CDN Par	Brent	WTI NYMEX	CDN Par	Brent	WTI NYMEX	CDN Par	Brent
Jan. 1991	23.74	23.63	24.70	25.03	25.91	25.30	25.31	25.62
Feb.	19.48	19.29	20.56	20.76	21.82	21.15	21.05	21.34
Mar.	18.83	19.64	19.88	20.11	21.66	20.48	20.39	21.40
Apr.	19.80	19.34	20.82	21.08	21.09	21.41	21.37	21.00
May	20.22	19.24	21.25	21.50	21.29	21.84	21.78	20.92
Jun.	19.15	18.17	20.20	20.44	20.35	20.80	20.72	19.78
Jul.	20.38	19.46	21.43	21.67	21.46	22.03	21.92	21.09
Aug.	20.55	19.77	21.68	21.84	21.83	22.28	22.09	21.35
Sep.	20.64	20.52	21.86	21.93	22.47	22.45	22.20	22.01
Oct.	22.07	22.21	23.23	23.37	24.14	23.83	23.64	23.71
Nov.	21.35	21.13	22.43	22.65	23.01	23.03	22.92	22.61
Dec.	18.49	18.28	19.53	19.77	19.95	20.13	20.04	19.72
Avg. 1991	**20.40**	**20.09**	**21.50**	**21.69**	**22.11**	**22.09**	**21.96**	**21.74**
Jan. 1992	17.61	18.18	18.82	18.91	19.87	19.42	19.22	19.64
Feb.	17.77	18.11	19.01	19.06	19.76	19.60	19.36	19.51
Mar.	17.63	17.60	18.95	18.92	19.17	19.55	19.21	18.99
Apr.	19.03	18.85	20.26	20.32	20.44	20.85	20.61	20.11
May	19.87	19.83	21.00	21.24	21.46	21.59	21.57	21.19
Jun.	21.29	21.19	22.36	22.66	22.79	22.96	22.99	22.53
Jul.	20.65	20.23	21.74	22.02	21.89	22.34	22.29	21.61
Aug.	20.24	19.79	21.29	21.60	21.47	21.88	21.94	21.15
Sep.	21.07	20.21	21.92	22.19	21.87	22.51	22.38	21.55
Oct.	20.82	20.34	21.71	21.94	22.04	22.30	22.12	21.72
Nov.	19.30	19.22	20.36	20.41	21.00	20.96	20.59	20.65
Dec.	18.17	18.22	19.43	19.27	19.99	20.03	19.45	19.72
Avg. 1992	**19.46**	**19.32**	**20.58**	**20.71**	**20.99**	**21.18**	**20.98**	**20.71**
Jan. 1993	17.43	17.39	19.07	18.67	19.14	19.67	18.98	18.98
Feb.	18.56	18.48	20.07	19.82	20.19	20.67	20.12	20.05
Mar.	18.65	18.80	20.36	19.91	20.50	20.95	20.22	20.39

Appendix VII
Average Regular Unleaded Gasoline Prices
(Self-Serve)
1992-1993

	1992				1993
	Mar. 31	**June 30**	**Sep. 29**	**Dec. 29**	**Mar. 30**
	cents per litre				
St John's (NFLD)	60.9	60.9	59.9	56.8	56.4
Charlottetown	60.3	60.0	60.4	58.5	56.5
Halifax	59.0	58.9	58.0	52.9	49.6
Saint John (N.B.) *	56.8	54.5	56.9	55.1	55.2
Montreal	59.0	61.8	59.5	59.8	58.0
Toronto	49.6	58.1	55.3	55.9	49.4
Winnipeg	46.8	53.9	47.9	53.9	51.9
Regina	41.9	43.9	49.9	56.9	48.9
Calgary	42.5	51.6	49.0	43.6	42.3
Vancouver	55.9	56.9	47.7	55.9	52.9
Average	**52.4**	**57.4**	**54.2**	**54.3**	**51.8**
Consumption taxes include:					
Federal	11.8	12.2	12.0	11.9	11.8
Provincial	13.8	14.0	13.9	14.0	14.0

* *Full-Serve*

Appendix VIII
Consumption Taxes on Petroleum Products
(March 1993)

	Ad valorem		Gasoline			Diesel
	Mogas	Diesel	Reg UL	Mid UL	Prem UL	
	%		(cents per litre)			
Federal Taxes						
Estimated GST (7%)			3.3	3.6	3.9	3.3
Excise			8.5	8.5	8.5	4.0
Provincial Taxes						
Newfoundland [a]			15.7	15.7	15.7	17.6
Prince Edward Island	23	26	11.7	11.7	11.7	11.7
Nova Scotia	24.5	31.5	10.9	10.9	10.9	13.6
New Brunswick			10.7	10.7	10.7	13.7
Quebec [b] [c]			18.8	19.2	19.5	16.7
Ontario			14.7	14.7	14.7	14.3
Manitoba			10.5	10.5	10.5	10.9
Saskatchewan			15.0	15.0	15.0	15.0
Alberta			9.0	9.0	9.0	9.0
British Columbia [d]			10.0	10.0	10.0	10.5
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	[c]	9.6	9.6	9.6	8.2
Average Provincial Tax			14.0	14.9	15.2	13.6

(a) The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay, Labrador.

(b) Incudes an estimated Quebec Sales Tax (8%) in addition to the gasoline tax of 14.5 cents per litre and the diesel tax of 12.6 cents per litre.

(c) Reduced by varying amounts in certain remote areas and within 20 kilometres of the provincial and U.S. borders.

(d) Additional transit tax of 3.0 cents per litre in Vancouver.

(e) 85% of gasoline tax.

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional area	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Synthetic crude oil	Crude oil production treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

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The Canadian Oil Market

Annual Review for 1993

Natural Resources Canada
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Canada

The Canadian Oil Market

Annual Review for 1993

Prepared by

Canadian Oil Markets and
Emergency Planning Division
Oil and Gas Branch
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PREFACE

"The Canadian Oil Market: Annual Review for 1993" provides an analysis of current developments in the oil industry on matters related to production, demand, pricing, and trade.

The review is intended as a service to the public. It is also used as an internal source of information in response to enquiries from within the Department, other federal/provincial departments, industry, universities, and other associations.

From 1986 to March 1993, the review was published quarterly. In early 1993, a decision was made to release only annual reviews, commencing with the 1993 Annual Review. This reduced publishing burden has allowed us to develop an NRCan electronic bulletin board (BBS) and a fax-on-demand service (FactsLine). These two electronic dissemination systems will permit most of our clients to access information on a more timely basis and in a more convenient format. To access the BBS call (613) 947-4748 and the Factsline (613) 947-4747. For assistance in using either system call FactsLine/BBS Help at (613) 992-8761.

"The Canadian Oil Market: Annual Review for 1993" was prepared by staff of the Canadian Oil Markets and Emergency Planning Division and the Petroleum Technology Division. Don Cunningham edited and supervised the analysis, Caroline Chapdelaine drafted many of the sections and coordinated the production of the document, and Bob Blondin, Mike Hnetka, Celia Kirlew and Randy Sheldrick, contributed to various sections of the report.

The Canadian Oil Markets and Emergency Planning Division gratefully acknowledges the use of data gathered and provided by Statistics Canada, the National Energy Board and through the courtesy of various oil and pipeline companies, industry associations and other sources in the preparation of this report.

Loretta Mahoney
Director
Canadian Oil Markets and Emergency Planning Division
Oil and Gas Branch
Natural Resources Canada

EXECUTIVE SUMMARY

This report provides an overview of the salient features of the Canadian oil market for 1993. It covers refined product demand, drilling activity, crude oil production, oil trade, pipeline issues, refinery activity, and pricing. The highlights of the report are summarized below.

- Demand for refined products continued to slowly recover in 1993 against a backdrop of generally stable product prices.
- Drilling activity almost doubled from the year before. Contributing to the increase in drilling activity were Alberta's crude oil royalty relief package, rising demand and improved prices for natural gas, a lower Canadian dollar and lower interest rates.
- Over the last two years Canadian crude oil production has risen by almost 10%, with most of the increase occurring in 1993. The growth in output occurred even though international oil prices were low and declining.
- Canadian imports of crude oil reached their highest level in 15 years. The increased level of imports stemmed from additional processing activity for the export market by most of the Atlantic refiners.
- Deliveries of crude oil to Canadian refineries rose in almost all regions as the economic recovery gathered momentum. However in B.C., receipts dropped by almost 30% as a result of two refinery closures.
- In 1993, 50% of Canadian crude oil production was exported, bringing exports to their highest level in twenty years. Sluggish oil demand in Canada, increasing domestic production and declining U.S. crude oil production all contributed to the higher level of exports. Reflecting the high volume of oil exports, Canada's 1993 oil trade surplus reached a record $3.4 billion.
- Monthly IPL apportionment levels reached historical highs in 1993, exceeding 40% towards the end of the year. Reflecting escalating levels of apportionment on the IPL system, TMPL deliveries rose, especially those destined for the export market.
- Canadian refinery rationalization continued during 1993. Refining capacity fell by 6%. The decrease in refinery capacity combined with an increase in refinery throughput raised the average refinery utilization by four percentage points to 84%.
- At the end of 1993, WTI fell to its lowest level since the fourth quarter of 1988. OPEC's inability to control members' production, weak demand by major oil-consuming nations, an unexpected surge in North Sea production, resilient Russian exports and the expectation of a resumption of Iraqi exports were the main factors for the continued downward price pressure. The declining Canadian dollar helped to offset the impact of declining international price on Canadian producers. Even so, the Canadian price of light sweet crude declined 7%, to a five year low.

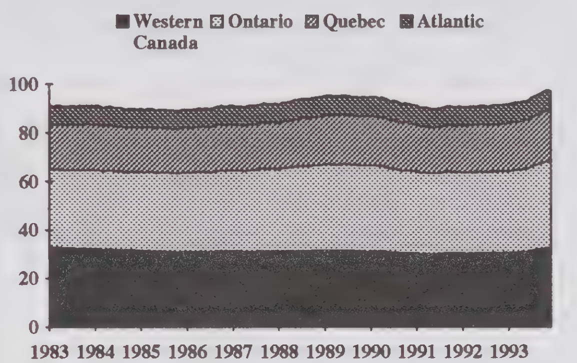
1. Refined Petroleum Product Demand

1.1 Demand

Total Demand

Demand for refined products continued to slowly recover in 1993, rising by 3 000 m^3/d or 1% from the previous year, to 221 000 m^3/d. Nevertheless, 1993 sales are some 15 000 m^3/d or 7% below their pre-recession peak in 1989. During the recession, sales of refined products fell steadily, averaging just 216 000 m^3/d by 1991. The modest upturn in demand since early 1992 has coincided with the recovery in the economy at large. The two main transportation fuels, motor gasoline and diesel, have accounted for most of the growth in product consumption over the last two years. The demand for heavy fuel oil has actually fallen slightly mainly because of a decline in oil-fired electricity generation in eastern Canada.

Figure 1.1.1
Motor Gasoline Sales
000 m^3/d



Motor Gasoline

About 90% of motor gasoline is sold at the retail pump. Sales of motor gasoline averaged 93 000 m^3/d in 1993, about 2 000 m^3/d higher than in 1992. As shown in Figure 1.1.1, motor gasoline sales have remained rather steady over the last decade, currently a mere 2 000 m^3/d higher than in 1983. Motor gasoline sales peaked in 1989, when they reached 95 000 m^3/d.

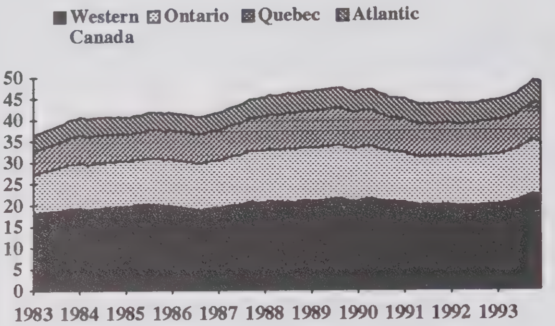
The Ontario market accounts for 37% of motor gasoline sales in Canada, commensurate with the region's population share. As such, gasoline consumption per capita in Ontario was on par with the national average of 3.3 litres per day in 1993. Per capita consumption in the other regions ranged from 2.8 litres per day in Quebec to 4.1 litres per day in the Prairies. The relatively high consumption levels in the Prairies reflect a number of factors including the region's greater population dispersion, an older, less fuel efficient car fleet (reflecting drier weather conditions), and generally lower gasoline prices (particularly in Alberta where there are significantly lower provincial road taxes).

Diesel

Sales of diesel fuel averaged 46 000 m^3/d in 1993, almost half the level of demand for motor gasoline. Diesel demand was about 2 000 m^3/d higher than the year before. Sales nevertheless remained below the 1989 peak of 47 000 m^3/d. The transportation sector accounts for almost two-thirds of diesel fuel demand in Canada. While cars, small trucks and vans are generally fuelled by motor gasoline, diesel is the dominant fuel in the trucking, railway, marine and urban transit sectors. Diesel is also widely used to power machinery and equipment in industry and agriculture. These two economic sectors currently account for about 15% and 10% of diesel fuel sales, respectively.

As shown in Figure 1.1.2, about 45% of diesel sales are in western Canada even though only 30% of the population resides there. As in the case of motor gasoline, the region's relatively high per capita consumption relates to greater

Figure 1.1.2
Diesel Sales
000 m^3/d

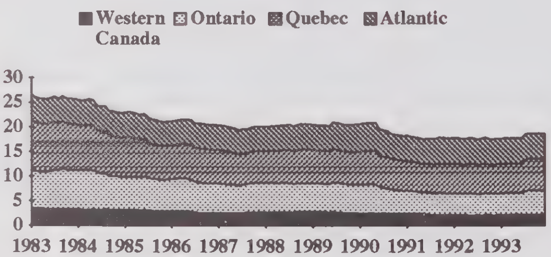


intra and inter urban distances. Moreover, diesel is the fuel of choice in the agricultural and petroleum industries, two industries which figure prominently in the western Canadian economy.

Heating Oil

After declining steadily during the 1980s, heating or light fuel oil demand at 18 000 m^3/d in 1993 (see Figure 1.1.3), has essentially remained flat since 1990. Over 85% of sales are east of the Prairie region. Western Canada's space heating requirements are almost entirely met from either natural gas or, to a lesser extent, electricity. The downward trend in heating oil sales observed during the 1980s mainly reflected a loss of share to natural gas and electricity in the space heating markets of Ontario and Quebec. The residential sector accounts for about 55% of heating oil demand. The remaining demand is about evenly split between the agricultural and office building sectors.

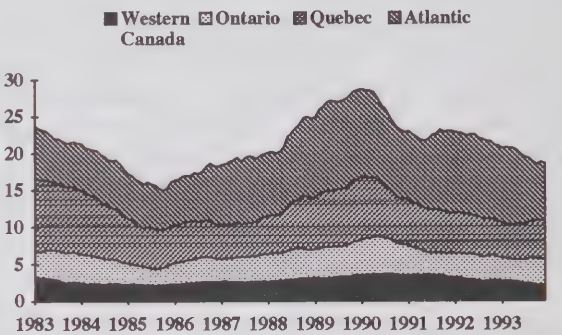
Figure 1.1.3
Heating Oil Sales
000 m^3/d



Heavy Fuel Oil (HFO)

Heavy fuel oil demand dropped by 2 000 m^3/d or 10% to 20 000 m^3/d in 1993 from the year before. Sales were also about 2 000 m^3/d lower than their 1983 level. Currently about 35% of heavy fuel oil is used to produce electricity. However, with most electricity in Canada traditionally produced from hydro and coal, only about 5% of power generation is HFO-based. The industrial sector accounts for about a third of HFO demand with the pulp and paper industry alone accounting for more than half of industrial consumption. Marine transportation makes up another 17% of HFO sales.

Figure 1.1.4
Heavy Fuel Oil Sales
000 m^3/d



As shown in Figure 1.1.4, the Atlantic region consumes almost half the HFO sold in Canada. In fact, the Atlantic region accounts for 85% of the demand for HFO in electricity generation (particularly in New Brunswick, where almost two-thirds of its electricity is generated from HFO). Quebec is also a relatively large consumer accounting for a quarter of total HFO sales. Quebec's pulp and paper industry accounts for about 37% of the region's demand and the marine transportation sector, 23%. Electricity generation accounts for about 10%.

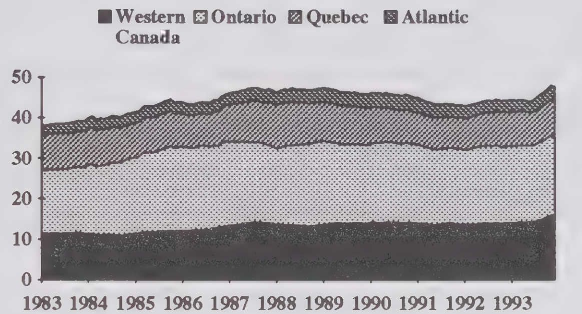
Less than 30% of HFO demand comes from Ontario and western Canada. Industries in these regions have more extensive pipeline access to western Canadian natural gas supply. Given that natural gas pipeline transportation costs are about five times those of oil on an energy equivalent basis, the cost advantage of using natural gas in lieu of oil diminishes progressively the further removed consumption is from production. This has been one reason industries west of Quebec have tended to favour natural gas, pipeline infrastructure permitting, and those in the east, oil.

Relative to other refined products, demand for HFO has been quite volatile over the last decade, with sales rising from 16 000 m^3/d in 1985 to a peak of 27 000 m^3/d in 1989. Since HFO competes with natural gas and electricity in some markets, demand for HFO is to some extent influenced by its relative price. The relatively low oil prices in the latter half of the 1980s did stimulate demand for HFO, as did the steady growth in the Canadian economy during this period. Nevertheless, about half the growth in HFO demand during this period was to compensate for a drought-induced shortfall in hydro-generation in Quebec and the Atlantic provinces.

Other Products

Other products include jet fuel, petrochemical feedstocks, asphalt, coke, LPGs, and lube oil & greases. Since these are usually relatively low volume, speciality products with few substitutes, their demand is relatively insensitive to the price of oil. However, consumption is not immune to the state of the economy: demand fell during the last two recessions. After having grown by 6 000 m^3/d between the end of the last recession in 1983 and 1990, 'other' product sales have levelled off at 44 000 m^3/d (see Figure 1.1.5) in the last three years. In 1993, Ontario demand accounted for 43% of total demand, followed by western Canada with 32%, Quebec with 19%, and Atlantic Canada with 6%.

Figure 1.1.5
Other Products Sales
000 m^3/d

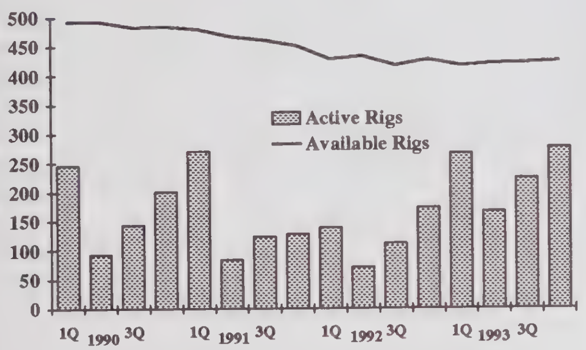


2. Drilling and Exploration Activity

2.1 Drilling Activity in Western Canada

Drilling activity in western Canada almost doubled in 1993. According to the Canadian Association of Oil Drilling Contractors (CAODC), drilling activity exceeded industry expectations with about 55% of all available drilling rigs active, compared to a record low 28% in 1992, 32% in 1991 and 35% in 1990. As shown in Figure 2.1.1, the number of available rigs has decreased from 500 in 1990 to 430 in 1993. The decrease in the number of available rigs coupled with the increased utilization, shown in Figure 2.1.1 on a quarterly basis, resulted in the improved utilization rate of 55%.

Figure 2.1.1
Drilling Activity in Western Canada
number of rigs



The drilling industry in western Canada, due primarily to weak crude oil and natural gas prices, had been on the decline for nearly a decade. 1985 was the last year that the industry reported more than 50% of its available rigs drilling - a level of activity considered necessary by the industry to break even.

In Alberta, just over half the province's rigs were drilling in 1993, compared to 30% in 1992. Rig utilization reached a peak of about 85% late in December, the highest in nearly eight years. Saskatchewan also experienced a surge in drilling activity with about 70% of its rigs active compared to 45% in the previous year. British Columbia lagged behind with only 42% of its rigs active, although still up from 19% a year earlier.

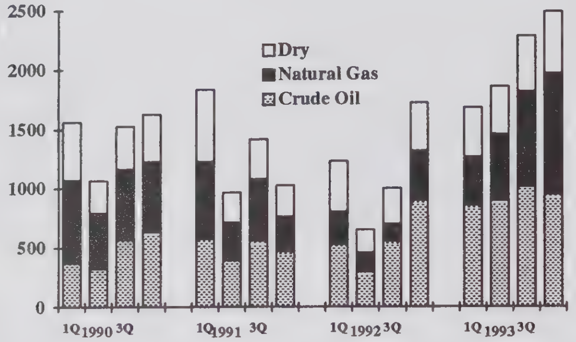
Some of this increase in drilling activity, particularly in the early stages of the recovery in western Canada, is credited to Alberta's October 1992 crude oil royalty relief package. Other factors such as rising demand and improved prices for natural gas, increased investor interest, a lower Canadian dollar and lower interest rates also contributed to the highest level of drilling activity in the region since 1985.

Alberta's royalty relief package included fundamental as well as temporary changes to the crude oil and natural gas royalty structures. Included were adjustments to the province's base royalty structure; a permanent twelve-month holiday for new oil exploration wells, and provisions to encourage investment in aging crude oil pools and the use of new drilling technology. But more importantly, it temporarily stimulated crude oil drilling by allowing new crude oil development wells to produce royalty free for a year.

Producers in Alberta anticipated the mid-year termination of the temporary measures of the royalty relief package and planned a large portion of their crude oil drilling activity for the first six months of 1993. A strong showing during the first quarter of the year (67%) was followed by a near record high number of rigs operating during the second quarter (40%), typically the slowest part of the year due to spring breakup and road closures.

As illustrated in Figure 2.1.2 on a quarterly basis, the total number of well completions in western Canada was up about 80% from a year earlier. The emphasis was on oil well development drilling. The total number of

Figure 2.1.2
Crude Oil and Natural Gas Wells
number of wells



metres drilled, was up only about 60% from a year earlier. According to the CAODC, the relatively smaller increase in metres drilled compared to the numbers of wells reflects the trend to shallower crude oil wells rather than deep gas wells that otherwise might have been drilled had it not been for the Alberta crude oil incentive package.

An anticipated drop-off in Alberta drilling activity following the termination of the temporary incentives on August 31, failed to materialize. Drilling activity across western Canada continued to increase over the latter half of 1993 driven by a significant swing to natural gas. While crude oil still remained the drilling industry's staple, natural gas well completions jumped from about a 35% share during the first half of 1993 to a 43% share over the last half of the year. With prices and demand up, natural gas drilling is expected to remain strong through 1994.

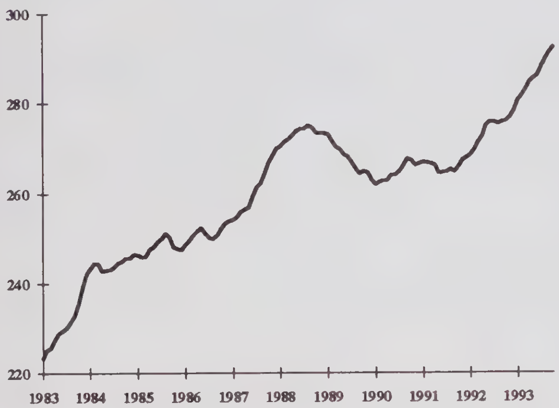
3. Crude Oil Supply

3.1 Domestic Production

Total

As shown in Figure 3.1.1, Canadian crude oil production has risen rather steadily during the last decade. Between 1983 and 1988, production grew by 44 000 m^3/d to almost 275 000 m^3/d. It fell back to the 265 000 m^3/d range in the following three years but started to rise again in 1992. Over the last two years production has risen by about 24 000 m^3/d to 290 000 m^3/d with an increase of 14 000 m^3/d in 1993 alone. In fact, production reached 305 000 m^3/d in August 1993, and averaged close to 300 000 m^3/d during the latter half of the year. The level of production achieved in 1993 was tantamount to about 3% of world oil production.

Figure 3.1.1
Crude Oil Production[1]
000 m^3/d



Increases in both conventional and non-conventional oil production occurred against a backdrop of declining international oil prices since 1991. However, because oil is de facto priced in U.S. dollars, an even steeper depreciation of the Canadian dollar vis-a-vis the U.S. dollar has, until recently, prevented oil prices in Canada from falling in tandem with international prices. The situation of stable and sometimes rising domestic prices persisted until mid-1993 when domestic oil prices belatedly began to drop as a result of both a deceleration in the rate of depreciation of the Canadian dollar and an acceleration in the decline in international oil prices.

Since the autumn of 1990, when the upturn in crude oil production began, Interprovincial Pipe Line (IPL), Canada's main oil pipeline, has had to consistently apportion pipeline space. Although IPL capacity constraints have not resulted in much shut-in to date, some producers have had to sell in less profitable markets.

Monthly IPL apportionment levels reached historical highs in 1993, exceeding 40% towards the end of the year. However, only a relatively small part of this apportionment was justified by the growth in crude oil production. Mostly, it stemmed from shippers anticipating apportionment and inflating their nominations accordingly so as to reserve line space. IPL and the oil industry have sought ways to mitigate over nominations by shippers but without much success. Recently, IPL received approval from the National Energy Board (NEB) to expand its throughput capacity which should reduce, if not eliminate, apportionment.

The strength of conventional light oil production in western Canada reflects significant rationalization in the Canadian upstream sector. This has created opportunities for smaller firms and new entrants. These firms have been acquiring properties from the majors, and taking advantage of lower interest rates as well as new exploration and development technologies, have

[1] Includes crude oil and pentanes plus but not NGLs as per Statistics Canada definitions.

embarked on aggressive drilling programs. The new E&D technologies include 3D seismic, horizontal drilling and continuous improvements in the design and metallurgical properties of drilling bits and pipe.

Successful exploration and development drilling for oil rose by 65% to 3700 wells. These wells helped sustain, if not increase, production in the conventional areas of western Canada. In Alberta, where typically three quarters of the wells are drilled, drilling was further bolstered by a provincially sponsored royalty relief package which applied to wells drilled between October 1992 and August 1993.

Conventional Light Crude Oil

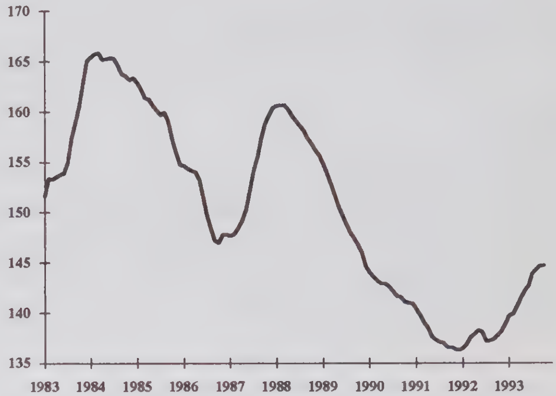
Conventional light crudes are generally produced from wells without altering the natural viscous state of the oil. Light/medium crude oil has a density of below 900 kg/m^3 (i.e. above 26°API).

Almost all conventional light (and medium) crude oil is produced in western Canada. Although Ontario has a long history of conventionl light oil production in the Sarnia area, production has traditionally been small and currently represents less than 1% of total domestic supply. Just recently, seasonal production has begun off the coast of Nova Scotia.

During the last decade there has been a secular decline in conventional light oil production. This downward trend is illustrated in Figure 3.1.2. Conventional light crude oil now accounts for a little less than half of Canada's crude oil output. Invariably, the decline has been attributed to the maturity of the western Canadian sedimentary basin and the attendant failure to discover any large reservoirs in recent years.

A modest upturn in conventional light production in 1993 stemmed from the start-up of the Cohasset/Panuke development off the coast of Nova Scotia in the summer of 1992, coupled with a small increase in production from western Canada. Production reached 140 000 m^3/d, about 3 000 m^3/d higher than the previous year (see Figure 3.1.2). Cohasset/Panuke is Canada's first offshore commercial development and could be adding as much as 6 000 m^3/d to Canada's light crude oil output once it reaches peak production in 1994.

Figure 3.1.2
Conventional Light Crude Production
000 m^3/d



Steady production in western Canada reflects the significant increase in drilling activity which helped to sustain, if not increase, production in the conventional areas. Alberta accounted for almost 80% of conventional light production and Saskatchewan followed with 10%. The remaining 10% was divided, in order of importance, between British Columbia, the Northwest Territories, Nova Scotia, Manitoba and Ontario.

Conventional light crude oil is expected to grow marginally in 1994, with incremental production reflecting the full operation of the Cohasset/Panuke project and another small increase from western Canada.

Synthetic Oil

Synthetic crude oil is a non-conventional light crude oil (about 33°API / 0.3% sulphur) produced from bitumen. Synthetic crude oil is produced at the large, integrated Syncrude and Suncor plants in Alberta, as well as the Newgrade and Bi-Provincial upgraders[2]. Open-

[2] Although the Newgrade and Bi-Provincial upgraders also produce synthetic light crude oil, in fact almost 15 000 m^3/d between them in 1993, the heavy crude

pit mining (or surface mining) and in situ methods are the two techniques used to recover bitumen. Syncrude and Suncor use open-pit mining at their oil sands plants because the bitumen deposits are near the surface. In this case, a process involving hot water, chemicals and mechanical separators segregates bitumen from sand and other impurities. The bitumen is then upgraded on site to light synthetic crude oil which makes it suitable for pipeline transportation to the refineries. At those refineries that are not specifially designed to process synthetic oil, it is sometimes blended with conventional light oil before being refined.

Synthetic crude oil production has grown over the last decade, from below 25 000 m^3/d in 1983 to a record 39 000 m^3/d in 1993. Despite some operational problems at both Syncrude and Suncor plants, production of synthetic crude increased by almost 2 000 m^3/d from 1992 levels.

Figure 3.1.3
Synthetic Oil Production
000 m^3/d

As shown in Figure 3.1.3, the upward trend in synthetic oil production has been quite erratic historically. The sometimes abrupt downturns in production have often resulted from unscheduled plant shutdowns because of fires or other operational problems. In 1993, an extended maintenance turnaround at the Syncrude oil sands plant reduced the plant's average production by a third in the first quarter.

Subsequently, Suncor underwent its own prolonged tunaround which brought operations to a halt for most of May 1993. The shutdown stemmed in part from fires in the upgrading units that caused a power outage; as well as the replacement of its bucketwheel excavators by a truck-and-shovel system. Suncor's investment in the truck and shovel system is expected to produce a cost saving of about $3 per barrel.

Notwithstanding the drop in synthetic output in the first half of 1993, Suncor and Syncrude both managed small annual increases in production, to 10 000 m^3/d and 29 000 m^3/d, respectively. This reflected near capacity production at both plants in the second half of the year. In fact, synthetic crude output reached a record-breaking 45 000 m^3/d in December with both plants operating at capacity.

With plans to further expand its capacity in 1994, Syncrude expects production to reach 31 000 m^3/d in 1994 while production at Suncor is expected to exceed 10 000 m^3/d.

Condensate

Condensate (aka pentanes plus) is mainly a by-product of natural gas production. Condensate normally has a high API, in the 55° to 60° API range, and a sulphur content below 0.3% by volume. About 60% of the condensate produced is used as a diluent for conventional heavy crude and bitumen to facilitate pipeline transportation. The remainder is shipped directly to the refineries and, in some instances, petrochemical plants. There is concern in the industry that, in the not too distant future, insufficient pentanes supply for blending could start constraining heavy crude oil production.

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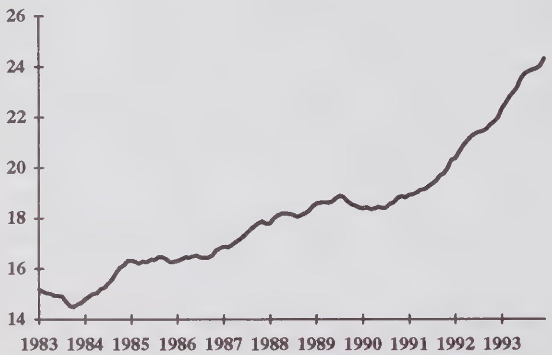
oil feedstock is supplied from producers not necessarily directly connected to the upgraders. Since the upgraders feedstock is reported under heavy crude oil production, in order to avoid double counting, the upgraders output is not included under synthetic crude oil output.

As shown in Figure 3.1.4, condensate production has risen from 15 000 m^3/d in 1983 to almost 24 000 m^3/d in 1993 with most of the growth occurring in the last three years. About 95% of the condensate comes from Alberta while Sakatchewan and B.C. produce the remaining 5%.

Output of condensate continued to increase, up by 10% or 2 000 m^3/d from the year before, to 24 000 m^3/d in 1993. The increase reflects Shell Canada's Caroline development, Alberta's largest natural gas field, which came on stream in early 1993. It is worth noting that although the Caroline development promises to be an important source of condensate supply, its high sulphur content renders it unsuitable for blending with heavy crude oil and bitumen. The industry is currently examining the economic feasibility of desulphurising this condensate so that it can be used for blending.

Figure 3.1.4
Condensate Production
000 m^3/d



Conventional Heavy Oil

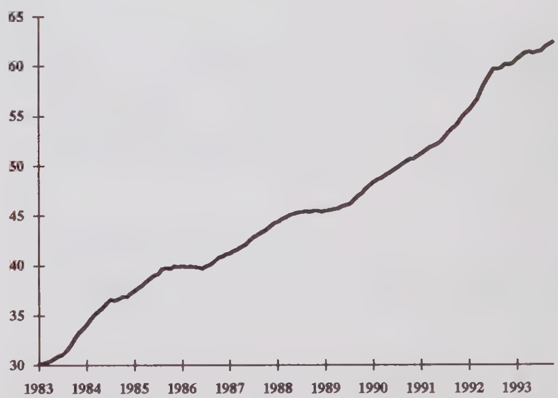
Conventional heavy crude oil is produced entirely in western Canada. It can be produced through a well without altering the viscosity of the oil. With a density generally greater than 900 kg/m^3 (less than 26° API), conventional heavy crude oil is often blended with condensate to facilitate pipeline transportation.

About 60% of the conventional heavy crude oil is produced in Alberta and the remaining 40% in Saskatchewan. Conventional heavy crude oil has accounted for an increasing share of total crude oil supply over the last decade. The steady increase in production has stemmed from growing demand, especially from U.S. refiners, and technological advances which have lowered recovery costs.

As shown in Figure 3.1.5, heavy crude oil production (excluding diluent) rose last year by 11% or 7 000 m^3/d to 67 000 m^3/d . An increase in Alberta production from 35 000 m^3/d to 40 000 m^3/d accounted for most of the rise in conventional heavy crude oil output. The new production was in response to the growth in demand for heavy crude oil following the installation of upgrading capacity at the Conoco refinery in Billings, Montana, and the Bi-provincial upgrader in Lloydminster.

Horizontal drilling is the most prominent but by no means the only recent technological advance that is improving the recovery rate and in particular the economics of heavy crude oil. Between 1988 and 1993, over 1 600 horizontal wells had been drilled in western Canada, more than half this number in 1993 alone. Horizontal production has made its greatest inroads in Saskatchewan where it accounts for about a

Figure 3.1.5
Conventional Heavy Production
000 m^3/d



quarter of total crude oil production even though horizontal wells make up only about 5% of all the active wells in the province.

Although technological improvements augur well for the future of heavy crude oil production, the rate of growth of heavy crude oil output will remain vulnerable to the level of future crude oil prices and growth in heavy crude oil demand.

Bitumen

Bitumen is a highly viscous crude oil, with a high sulphur content. Having a gravity of more than 1 000 kg/m^3 (or less than 10° API), bitumen must be made less viscous with heat so that it can flow into a well bore. The 'in-situ' method is commonly applied to extract deeply buried bitumen deposits. This involves steam injection, which brings the raw bitumen to the surface. To make it suitable for pipeline transportation, bitumen must be blended with condensate.

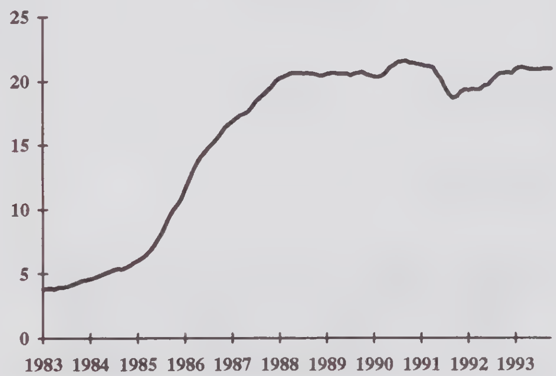
Alberta has one of the world's largest bitumen resources and, in fact, produces all of the bitumen in Canada. Alberta bitumen deposits are concentrated in the Athabasca, Cold Lake, and Peace River areas.

In 1983, bitumen production averaged just 4 000 m^3/d. By 1993, production had risen five-fold to 21 000 m^3/d albeit with most of the increase occurring between 1985 and 1988, following the start-up of Imperial Oil's Cold Lake project.

Reflecting the October 1992 start-up of Phases 7 and 8 of the Cold Lake project, bitumen production rose by 1 000 m^3/d in 1993 (see Figure 3.1.6). Recent successes using experimental technology make further gains in bitumen output likely. The industry expects output to approach 23 000 m^3/d in 1994.

However, future bitumen development could be jeopardized by low crude oil prices. Several bitumen projects and expansions announced prior to the recent drop in crude oil prices have now been postponed, pending higher and more stable oil prices. For example, Imperial Oil Limited shelved plans to start-up Phases 9 and 10 at Cold Lake. The two phases were expected to add between 3 000 to 4 000 m^3/d to Cold Lake's current production of 16 000 m^3/d. Amoco Canada Limited is also reconsidering whether to go forward with its 8 000 m^3/d Primrose bitumen project.

Figure 3.1.6
Bitumen Production
000 m^3/d



3.2 Imports

Total

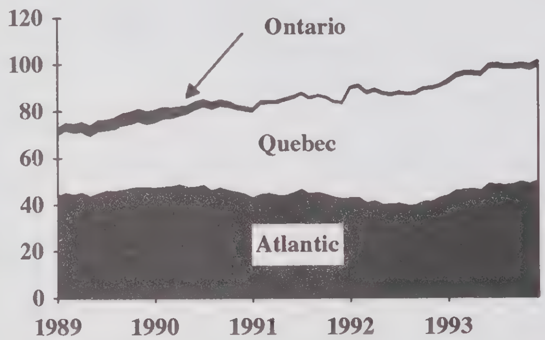
Canadian imports of crude oil (and some partially processed oil) reached their highest level in 15 years in 1993. Averaging 98 000 m^3/d, imports rose by 10% or 9 000 m^3/d from the previous year. The increase essentially resulted from more processing activity for the export market on the part of the Atlantic refiners.

A small refiner in Nova Scotia began processing for the export market in early 1993. Product exports under these processing agreements had previously dropped off, in part, because of a prolonged turnaround in the fall of 1992 at the Newfoundland Come-by-Chance refinery which markets most of its refined products in the New England states.

OPEC crudes accounted for an unusually large share of total imports in 1993, at least compared to recent years. Imports from OPEC rose to 42% in 1993 vis-a-vis the 30% range more typical in the years since oil market deregulation in 1985. Most of the growth in OPEC deliveries came from Nigeria, Algeria and Iran. In fact, Nigeria overtook Saudi Arabia as the largest single supplier of OPEC crude to Canada last year.

The growth in OPEC's share came at the expense of North Sea deliveries. North Sea imports fell to just 47% of imports in 1993. This is to be compared to a 60% share in 1992, which was more representative of recent years. A drop in imports from Norway accounted for all the decline, with deliveries from the U.K. increasing. Nevertheless, the U.K. and Norway remained, by a wide margin, Canada's two largest suppliers of crude oil imports, together making up over 80% of non-OPEC imports.

Figure 3.2.1
Crude Oil Imports
000 m^3/d



In 1993, the Atlantic refineries absorbed a larger share of total imports compared to the previous year. In 1992, imports were almost evenly split between Atlantic and Quebec refiners. However, in 1993, about 53% of total imports were delivered to Atlantic refiners while Quebec's share dropped to 46%. Ontario's crude oil imports have remained minimal.

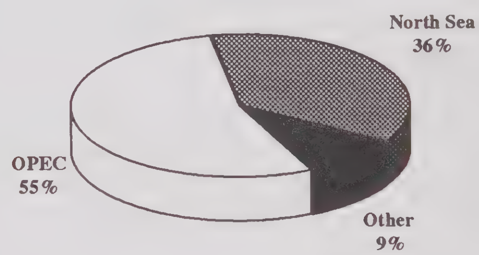
Figure 3.2.1 illustrates the breakdown of imports by region since 1989. Crude oil imports have grown by about 21 000 m^3/d over the last five years with Quebec accounting for most of the growth. Since 1989, Quebec imports have risen by 18 000 m^3/d. The latter largely reflects the Montreal refiners' virtually complete conversion from western Canadian to foreign offshore feedstocks by early 1991.

Atlantic

Atlantic refiners imported about 53 000 m^3/d in 1993. This was 8 000 m^3/d or almost 20% higher than in 1992. Some of the increase simply represented a recovery from 1992 when a lengthy turnaround at the Come-by-Chance refinery in Newfoundland had the effect of lowering the annual level of crude runs in the region by some 3 000 m^3/d. The rest of the increase reflected incremental product exports.

Imports from OPEC increased by 4 000 m^3/d to 28 000 m^3/d in 1993, with Nigeria accounting for all the increase. As shown in Figure 3.2.2, OPEC crudes accounted for 55% of Atlantic oil imports with most OPEC supply coming from Saudi Arabia and Nigeria. Imports from non-OPEC countries also rose by 4 000 m^3/d, to 24 000 m^3/d, with North Sea crudes accounting for 36% of total Atlantic imports.

Figure 3.2.2
Atlantic Crude Oil Imports



Between 1989 and 1993, crude oil imports in Altantic Canada rose by 15% or 7 000 m^3/d. This completely reflects the increase in processing activity since demand for refined

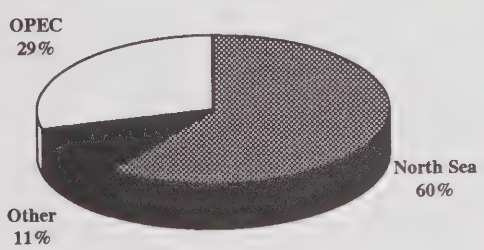
products in the domestic market has actually fallen while refined products exports have grown by 10 000 m^3/d during this period.

Quebec

Montreal refiners have continued to rely almost entirely on foreign crude oil feedstocks despite the re-opening of the Sarnia-Montreal extension after it was temporarily closed from mid-1991 to mid-1992. Only very small volumes of domestic crude were delivered to Montreal during 1993 (about 1 000 m^3/d). North Sea light and Mexican heavy crude oil have mainly been used in lieu of similar grades of western Canadian crude oil. In 1993, OPEC crudes increased their market share in Quebec although they continued to account for less than 30%, as indicated in Figure 3.2.3.

The increase in OPEC imports more than offset a decline in North Sea imports, such that crude oil imports in Quebec went up in 1993 by 2 000 m^3/d to 44 000 m^3/d. OPEC imports tripled to 13 000 m^3/d with Nigeria accounting for about half the increase. Imports from Nigeria rose by about 4 000 m^3/d.

Figure 3.2.3
Quebec Crude Oil Imports



On the other hand, non-OPEC imports dropped by almost 8 000 m^3/d to 32 000 m^3/d, with lower North Sea deliveries accounting for most of the drop. Norway imports declined by 4 000 m^3/d to average 7 000 m^3/d. U.K. imports remained unchanged at 20 000 m^3/d.

Quebec refineries received most of the crude that was imported from Mexico. The heavier Mexican crudes are mainly for asphalt production. Imports from Mexico reached 5 000 m^3/d in 1993, their highest level since 1985.

4. Crude Oil Disposition

4.1 Refinery Receipts

Total

Deliveries of crude oil[1] to Canadian refineries rose by 9 000 m^3/d to 242 000 m^3/d in 1993, having previously fallen to their lowest level in five years in 1992. The increase in refinery receipts was largely confined to the Atlantic region whose refineries are increasingly refining foreign crude for the export market. This was reflected in the fact that, while receipts of domestic crude oil declined by about 1 000 m^3/d from the year before, deliveries of foreign crudes, almost all to Atlantic and Quebec refiners, rose by almost 10 000 m^3/d, to over 98 000 m^3/d.

Domestic crude deliveries accounted for 58% of total refinery receipts. Virtually all of the domestic deliveries were directed to refiners located west of Quebec. Ontario remained the largest regional market for domestic crude, with a 47% share. Prairie refiners accounted for 40%, and British Columbia refiners, 11%.

Demand for Canadian crude oil in the Atlantic and Quebec regions accounted for less than 3% of total domestic crude receipts. The small volumes of domestic crude (averaging below 1 000 m^3/d) reaching Quebec resulted from the re-opening of IPL's Sarnia-Montreal extension in mid-1992 which reconnected the two refineries in Montreal to western Canadian crude oil supply. The 2 000 m^3/d delivered to the Atlantic refiners came from the Cohasset/Panuke project off the coast of Nova Scotia.

A slight increase in the demand for domestic heavy crude oil was entirely offset by reduced demand for domestic light crude oil. The latter averaged 121 000 m^3/d, about 1 000 m^3/d less than the year before. Heavy crude deliveries[2] averaged almost 23 000 m^3/d.

Atlantic

As illustrated in Figure 4.1.1, crude oil receipts in Atlantic Canada in 1993 rose by 20%, or almost 10 000 m^3/d, to 55 000 m^3/d. Since demand for refined products in the region was essentially flat, the incremental receipts stemmed from processing agreements to supply products

Figure 4.1.1
Atlantic Crude Oil Receipts
000 m^3/d

[1] Imports of partially processed oil are included in crude oil receipts. However, to avoid double counting, transfers of partially processed oil from other Canadian refineries are not included.

[2] Heavy crude oil delivered to Regina's Newgrade upgrader is considered a refinery receipt while similar deliveries to the Bi-Provincial upgrader in Lloydminster are not. In the case of the Newgrade upgrader, most of the upgrader's light crude oil output is used by the adjacent Consumer's Co-Op refinery whose operations are in effect integrated with those of the upgrader. On the other hand, Bi-Provincial's upgraded crude is not closely tied to any particular refinery. Thus, to avoid double counting, Bi-Provincial's output is treated as a light crude oil receipt once it reaches a refinery.

to foreign markets. Reflecting this fact, exports of refined products from the Atlantic grew by 11 000 m^3/d in 1993. The Atlantic region has become a large net exporter of finished products, accounting for over 90% of Canada's net exports. In fact, only about half of the products refined in the Atlantic, are for the local market with two of the four refineries in the region essentially dedicated to, and a third heavily involved in, refining for the export market.

The 55 000 m^3/d delivered to the Atlantic region represented almost 23% of total receipts in Canada. A little more than half of the crude oil delivered in the Atlantic region came from OPEC countries, predominantly from Nigeria and Saudi Arabia. The bulk of the remainder came from the North Sea.

Quebec

Crude oil receipts in Quebec rose by 3% or 1 000 m^3/d to 46 000 m^3/d, as shown in Figure 4.1.2. After declining during the recession,

Figure 4.1.2
Quebec Crude Oil Receipts
000 m^3/d

crude oil demand started to increase in mid-1992. Reduced product imports against a backdrop of flat demand for refined products in the regional market was the main reason for the upturn. Moreover, a Quebec refinery increased its product transfers to the Atlantic market after its Atlantic affiliate began refining exclusively for the export market in early 1993.

Quebec refineries accounted for 19% of total crude oil demand in Canada. Quebec receipts mostly consisted of North Sea crudes. Only about a 1 000 m^3/d came from western Canada, despite the re-activation of the Sarnia-Montreal extension in the previous year. These relatively small domestic volumes likely reflect chronic undercapacity on the western Canadian section of the IPL system and the Montreal refineries' preferences for imported crude.

Ontario

After having declined steadily since mid-1989, crude oil receipts in Ontario rose marginally to 69 000 m^3/d in 1993 (see Figure 4.1.3). The rise in receipts was in line with an equally marginal increase in the demand for refined products in

Figure 4.1.3
Ontario Crude Oil Receipts
000 m^3/d

the region. Ontario was the first region to be affected by the recession and ultimately was the most severely affected by it. This was reflected in the trend in the region's oil demand. Crude oil receipts fell to 68 000 m^3/d in 1992 from their 79 000 m^3/d peak in 1989.

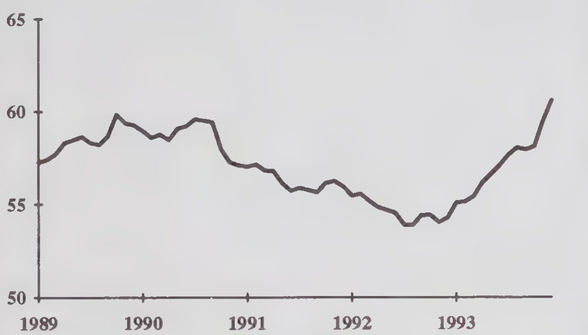
Nevertheless, Ontario remained the largest crude oil market in Canada, accounting for 29% of total receipts in 1993. Apart from about 1 500 m^3/d of foreign crude, mostly from the North Sea, pipelined up from the U.S. Gulf, almost all of Ontario's receipts were delivered via IPL from western Canada. Almost 85% of

domestic deliveries were made up of light crude oil and equivalent, i.e. conventional, synthetic, and pentanes plus. These averaged 41 000 m^3/d, 13 000 m^3/d, and 4 000 m^3/d, respectively. Averaging 10 000 m^3/d, heavy crude oil accounted for 15% of Ontario receipts.

Prairies

As shown in Figure 4.1.4, after having declined during the recession, crude oil receipts in the Prairies rose by 4 000 m^3/d to average 58 000 m^3/d in 1993 as the economic recovery gathered momentum. Prairie receipts accounted

Figure 4.1.4
Prairies Crude Oil Receipts
000 m^3/d



for about 24% of the national total. The upturn in Prairie receipts also reflected the conversions during 1993 of the Shell and Petro Canada refineries in the Vancouver area to refined product terminalling and blending facilities. These conversions in effect removed almost 8 000 m^3/d, or a third of British Columbia's refinery capacity, by mid-year. To maintain their presence in the west coast market, Shell and Petro-Canada now ship refined products from their refineries in Edmonton to their newly converted distribution terminals in the Vancouver area via the Trans Mountain Pipe Line.

Prairie refineries processed domestic crude oil exclusively, 80% of which was light crude oil. Receipts of conventional and synthetic light oil averaged 27 000 m^3/d and 19 000 m^3/d, respectively. Averaging 12 000 m^3/d, heavy crude oil accounted for the remaining 20% .

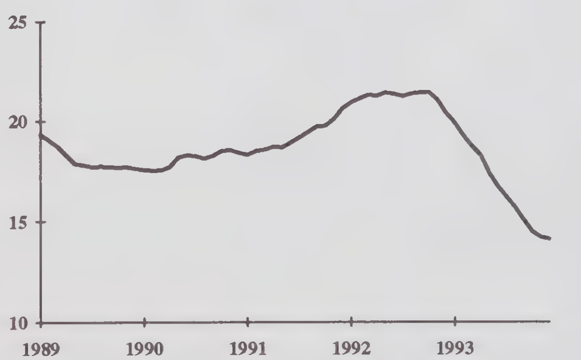
British Columbia

The two refinery closures caused crude oil receipts in B.C. to plunge by 5 000 m^3/d, in 1993. Refinery receipts fell progressively from 22 000 m^3/d in the first quarter to just 11 000 m^3/d in the last quarter. Over the year, B.C. receipts averaged 16 000 m^3/d, not far below the region's current refining capacity. Crude oil demand in B.C. is bound to fall further still given Esso Petroleum's announced intention to convert its 7 000 m^3/d Ioco refinery to a distribution terminal by mid-1994.

Domestic light crude oil accounted for 95% of the region's crude receipts. Most of this was conventional light oil (14 000 m^3/d) plus a small amount of synthetic (about 1 000 m^3/d). Heavy crude oil deliveries (also about a 1 000 m^3/d) made up the difference.

The British Columbia economy largely escaped the worst effects of the recent recession. Refined product demand remained essentially flat over the entire 1990-93 period, unlike other regions where the recession led to significant reductions in product demand. Nevertheless, as shown in Figure 4.1.5, crude oil receipts

Figure 4.1.5
B.C. Crude Oil Receipts
000 m^3/d



declined before rising again in 1992. Higher deliveries of partially processed oil from sister

refineries in Edmonton in lieu of crude oil explains the lower volumes of crude oil demanded in the years prior to 1992. Receipts of partially processed oil averaged as high as 5 000 m^3/d in 1990, having since fallen to almost zero by 1993.

Since partially processed oil receipts are not included, the figure understates the volume of oil feedstocks that the B.C. refiners were actually processing in the earlier years.

4.2 Crude Oil Exports

Total Exports

In 1993, Canadian crude oil exports reached their highest level in twenty years. Averaging 147 000 m^3/d, exports were 13 000 m^3/d higher than a year earlier, and almost 42 000 m^3/d higher than in 1990. Exports peaked in October, reaching 160 000 m^3/d.

Sluggish oil demand in Canada and increasing domestic production boosted exports. Since 1990 Canadian refinery demand has fallen by 21 000 m^3/d while production has risen by 25 000 m^3/d, resulting in an excess supply of crude oil over domestic requirements of more than 45 000 m^3/d.

Figure 4.2.1
Crude Oil Exports
000 m^3/d

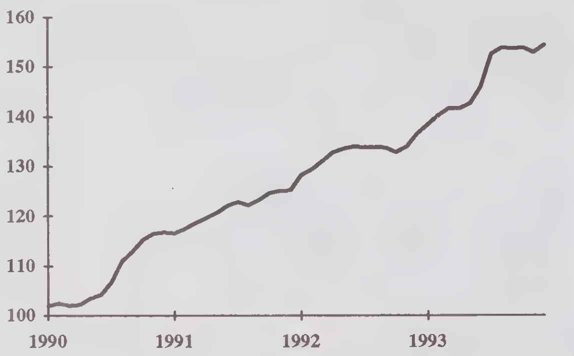
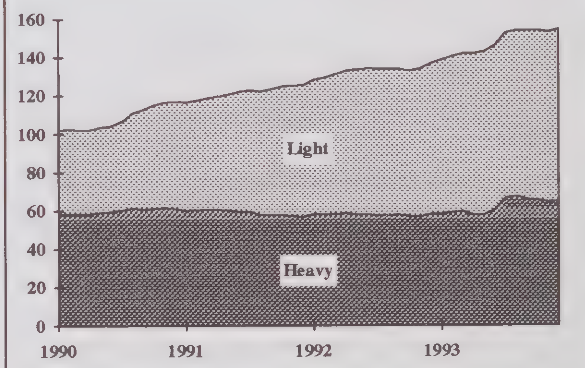


Figure 4.2.2
Crude Oil Exports by Type
000 m^3/d



This excess supply has found a ready market in the United States where indigenous production is declining and the demand for foreign crude is therefore growing. In 1993, about half of Canada's crude oil production was exported (virtually all to the United States) compared to 37% in 1990 and 30% in 1985.

Exports by Crude Oil Type

As illustrated in Figure 4.2.2, light crude oil and equivalent has accounted for most of the growth in exports over the last few years. Exports of conventional light crude oil rose by almost 6 000 m^3/d to 68 000 m^3/d from the year before. This reflects a small upturn in conventional light crude oil production. However, more importantly, the volume of light crude oil available for export has been inflated in recent years by the blending of heavy crude into light crude streams at the feeder line stage prior to entering major trunk lines for delivery to the refineries. By the same token, blending reduces the volume of heavy crude oil that would otherwise be available for export.

It is estimated that about 8 000 to 10 000 m^3/d of heavy crude production is currently being

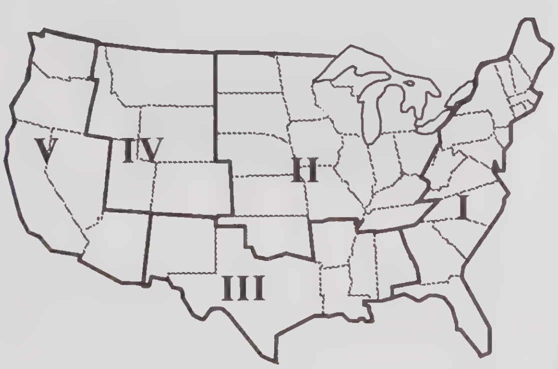
blended with light crude oil. Although blending lowers the quality of the light crude streams, its overall impact on producers' netbacks is not as clear. While the average price of the light crude oil should drop because of its lower quality, there is now more of it to sell. Moreover, by reducing supply in the heavy crude oil market, blending tends to raise heavy crude oil prices. This is perhaps one factor contributing to the decline in the price differential between heavy and light crude oil. Other often cited factors include a similar narrowing of the differentials in the international market and the increase in upgrading capacity in Canadian and U.S. northern tier markets.

Blending did not prevent exports of heavy crude oil from rising by 2 000 m^3/d in 1993 to 60 000 m^3/d. Moreover, exports of condensates and synthetic crude each increased by about 1 000 m^3/d, to 5 000 m^3/d and 11 000 m^3/d, respectively.

Exports by PADD

PADD is the acronym for the Petroleum Administration for Defense Districts. The U.S. is divided into five PADDs. These are shown in Figure 4.2.3. In Figure 4.2.4, exports to PADD I and II are shown under U.S. Great Lakes; while those to PADD III, IV, V, and east Asia are included under "other".

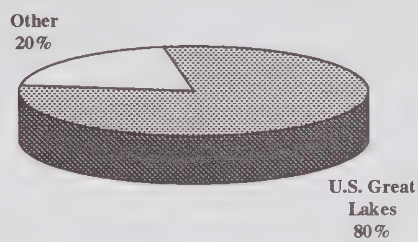
Figure 4.2.3
U.S. PADDs



As has traditionally been the case, about 80% of Canadian exports were delivered to refiners in the U.S. Great Lakes region in 1993, making this the largest single market for Canadian crude.

Deliveries to PADD II reached 106 000 m^3/d, 3 000 m^3/d higher than the year before. In fact, they were as high as 120 000 m^3/d in October. Exports to PADD I also rose, increasing by 2 000 m^3/d to 11 000 m^3/d.

Figure 4.2.4
Crude Oil Exports by Destination



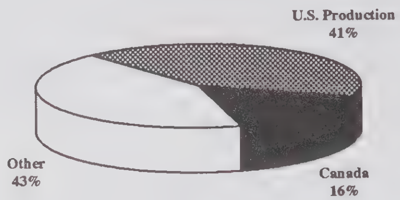
The Chicago market remained the preferred market, notwithstanding the fact that Canadian producers have had to sell their crude at discounts reportedly in the \$0.50 to \$1 per barrel range. These discounts have largely been attributed to IPL apportionment, which renders Canadian crudes less marketable because their delivery cannot always be guaranteed (see Chapter 5 on Major Oil Pipelines).

With exports to the U.S. Great Lakes region reaching 117 000 m^3/d last year, Canadian crudes accounted for about 16% of the region's total crude oil receipts. As shown in Figure 4.2.5, most of the Great Lakes region's crude oil requirements were met from imports pipelined up from the U.S. Gulf Coast, and from U.S. indigenous production.

Limited capacity on the IPL system has also forced Canadian producers to seek alternative, and usually less profitable, markets for their crudes. Using a spur line connected to the Trans

Mountain Pipe Line system, exports to PADD V's Puget Sound refineries in Washington State almost tripled, rising by 7 000 m^3/d to 11 000 m^3/d. PADD V accounted for about 7% of the total exports compared to less than a 2% share as recently as 1991.

Figure 4.2.5
Crude Oil Demand
U.S. Great Lakes

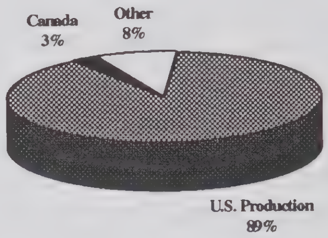


Exports to PADD V also increased following the closure of two small refineries in British Columbia. Some B.C. crude production was now having to find a market in Washington State.

PADD IV refinery receipts of Canadian crudes rose by almost 2 000 m^3/d or 13% to 17 000 m^3/d. This resulted mainly from higher demand for Canadian heavy crude oil at the Conoco refinery in Billings, Montana, which in mid-1992 increased its capacity to upgrade heavy crude.

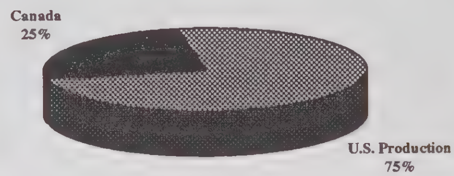
As shown in Figure 4.2.6 and 4.2.7, refineries in PADD IV and V rely much less on foreign crudes than PADD II, with U.S. crudes meeting almost 75% and 90% of PADD IV and V's crude oil requirements, respectively. However, demand for Canadian crude oil in these regions is bound to grow over the next decade given the projections of declining crude oil production in the Rocky Mountain region and Alaska.

Figure 4.2.6
Crude Oil Demand
PADD V



Recently, Canada has accounted for almost a quarter of the 70 000 m^3/d of crude oil supplied to the PADD IV market, as shown in Figure 4.2.7. On the other hand, of the 400 000 m^3/d delivered to PADD V refineries, Canada's share was only 3%, with imports from other countries accounting for 8% of the market.

Figure 4.2.7
Crude Oil Demand
PADD IV



Exports to PADD III (the U.S. Gulf region), typically account for less than 2% of total Canadian exports. The reason is that they normally take the circuitous route via Vancouver and the Panama Canal, thereby incurring high

transportation costs. In 1993, they remained low at about 1 000 m^3/d.

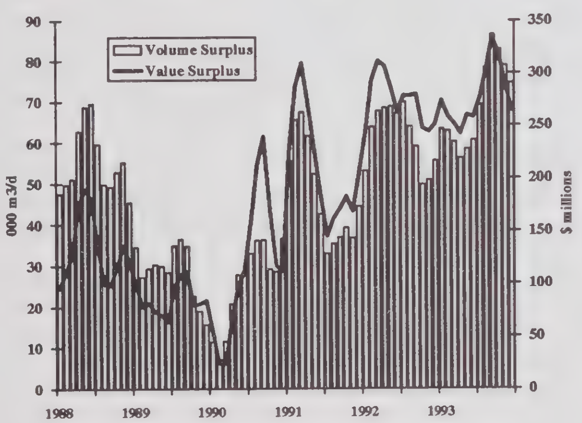
With its crude oil exports growing, Canada ranked among the top five exporters to the U.S. along with Saudi Arabia, Venezuela, Mexico and Nigeria. Canada's share of total U.S. imports amounted to 11%. In fact, Canada was the largest exporter in October, with exports averaging 160 000 m^3/d during that month.

4.3 Canada's Oil Trade Balance

Canada's oil trade surplus reached a record level of $3.4 billion in 1993, reflecting relatively high net exports of both crude oil and refined products. Crude oil and refined product exports averaged $9.6 billion, up by $600 million from 1992. Meanwhile, the value of crude oil and refined product imports averaged $6.2 billion, about $500 million higher than 1992.

Figure 4.3.1 shows the value and volumetric trends in the oil trade surplus over the past six years. As indicated in the figure, oil contributed almost $280 million per month to Canada's merchandise trade balance in 1993. By comparison, from early 1989 to mid-1990, oil's contribution was generally below $100 million per month.

Figure 4.3.1
Canada's Oil Trade Surplus



It was a rapid, albeit short-lived, rise in crude oil prices during the Persian Gulf conflict that initially elevated the value of the trade surplus in the latter half of 1990. Canada, as a net oil exporter gained more than it lost from the increase in oil prices. This is suggested in the Figure 4.3.1 by the greater escalation in the value of the surplus vis-a-vis the volumetric surplus during the fall of 1990.

Despite oil prices having fallen back to pre-conflict levels by early 1991, the value to volume ratio of net exports has remained quite high compared to the two years prior to the Persian Gulf conflict. This is because Canada's net exports now consist of proportionally more higher-valued light crude oil and refined products than before. Nevertheless, declining crude oil prices in the second half of 1993 led to some deterioration in the value to volume ratio of net exports, as shown in Figure 4.3.1.

Trends in Canada's volumetric oil trade surplus are closely tied to developments in the domestic oil sector. Figure 4.3.2[3] shows Canada's trade surplus in crude oil and refined products as the difference between crude oil production and refined product consumption.

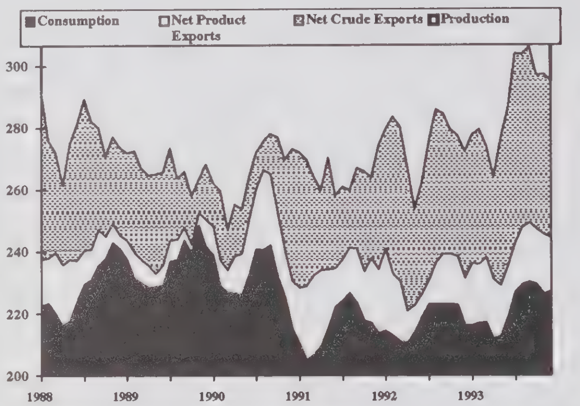
As shown in Figure 4.3.2, the surplus steadily narrowed during 1988 and 1989 as a result of falling production and rising consumption. The turnaround occurred when high oil prices during the Persian Gulf conflict bolstered production while dampening demand for refined products.

[3] The trend in net oil exports in Figure 4.3.2 only approximates that of Figure 4.3.1. Figure 4.3.1 is based on Canada Customs data while Figure 4.3.2 is based on data from the Industry Division of Statistics Canada. Divergences may occur because of differences between the two agencies in the classification and timing of the reported data. Divergences can also occur because Figure 4.3.2 does not include changes in oil inventories.

At the same time, the recession also began exerting strong downward pressure on product demand. Product sales plummeted in the fourth quarter of 1990 and have essentially remained in a slump ever since. Rising crude production has been the other factor underlying the growth in net exports during the last three years.

As Figure 4.3.2 illustrates, net exports of both crude oil and refined products have risen substantially since 1990. This is partly because

Figure 4.3.2
Oil Production, Consumption and Net Trade
000 m^3/d



of higher crude production; and partly because domestic refiners have curtailed their demand for crude oil while increasing product exports to help offset the drop in domestic sales.

5. Major Oil Pipelines

5.1 Deliveries

Virtually all Canadian crude oil is produced in western Canada, with Alberta alone accounting for 80% of total production. On the other hand, most oil demand is in central Canada and the U.S. export market. Canada's crude oil pipeline network connects western Canadian supply to refineries located in the regions where most of the oil is consumed. Figure 5.1.1 is a schematic of the Canadian oil pipeline network. The pipeline network is dominated by two pipelines which together transport over 90% of the domestic oil delivered by pipeline. Interprovincial Pipe Line (IPL) delivers east from Edmonton while Trans Mountain Pipe Line (TMPL) delivers west.

Figure 5.1.1
Major Crude Oil Pipelines

TMPL

TMPL receives most of its Alberta crude at its Edmonton terminal. TMPL also delivers British Columbia crude which it receives from the Westcoast pipeline in the B.C. interior. In addition to crude oil, TMPL delivers semi-refined and refined products to the domestic and export markets on the west coast. The bulk of its deliveries are to the refineries and terminals in the Vancouver area, and to a products terminal in Kamloops. A small volume of crude normally reaches TMPL's Westridge Marine Terminal for transhipment to offshore export markets and increasingly to U.S. refineries in the Puget Sound area of Washington state. In addition, TMPL delivers crude oil directly to four of the seven refineries in the Puget Sound area which are connected by a spur pipeline to TMPL's main line.

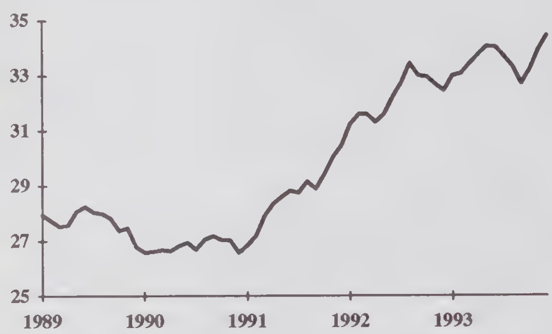
TMPL's throughput averaged 34 000 m^3/d in 1993, about 6% or 2 000 m^3/d more than the previous year. An increase in exports more than offset a fall in domestic deliveries. Throughput destined for export markets averaged 12 000 m^3/d in 1993, roughly 70% or 5 000 m^3/d higher than the year before. Crude oil pipelined to the Puget Sound refineries increased by 6 000 m^3/d to 9 000 m^3/d, accounting for 28% of total Trans Mountain throughput. TMPL loaded the remaining 3 000 m^3/d onto tankers and barges at its Westridge marine terminal, most of which also found its way to the Puget Sound area. The Westridge marine terminal's share of total throughput declined from 12% in 1992 to 8% in 1993 because of a decline in Far East deliveries.

Crude oil demand in B.C was curtailed in 1993 when two refineries in the Vancouver area were converted to terminalling and product finishing facilities by mid-year. The closures effectively removed about 8 000 m^3/d, or a third of B.C.'s refining capacity. However, TMPL's deliveries of refined products rose because now Edmonton refiners were supplying a larger share of the B.C. oil products market.

TMPL's total domestic deliveries averaged about 22 000 m^3/d, down by 3 000 m^3/d from 1992. Thus the B.C. market accounted for only 65% of total TMPL deliveries in 1993 compared to almost 80% in 1992.

Figure 5.1.2, shows that TMPL deliveries have increased by 20% or 6 000 m^3/d in the last three years. The rise in throughput mostly reflects escalating levels of apportionment on the IPL system which has forced Canadian producers to find alternative markets for their oil. Increased exports to Washington refineries have accounted for all the growth in TMPL throughput.

Figure 5.1.2
TMPL Deliveries
000 m^3/d



IPL

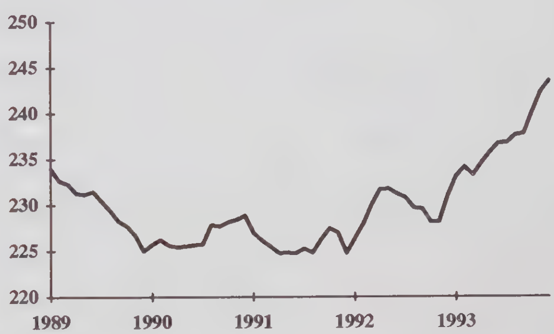
Also originating in Edmonton, the Interprovincial Pipe Line (IPL) system stretches some 3 700 kilometres east to Montreal, Quebec. The IPL system comprises three interconnected parts: the western Canadian, U.S. Lakehead, and eastern Canadian sections.

The western section travels south-east through Regina, Saskatchewan and crosses the border into the United States near Gretna, Manitoba. The Lakehead portion serves the U.S. Great Lakes region via two separate lines to the north and south of Lake Michigan that eventually rejoin at Sarnia, Ontario. The eastern section extends through Ontario to Montreal and also regularly supplies a refinery in U.S. PADD I through a connection with a small pipeline on the U.S. side of the border.

IPL delivers about half its oil to the U.S., 35% to Ontario, and 13% to the Prairies. Montreal currently receives less than 1% of total deliveries. The Sarnia-Montreal section of the IPL was in fact purged and closed in mid-1991 only to be re-opened in mid-1992. Since the reopening, only small volumes have reached the Montreal market.

Total IPL deliveries of crude oil, refined products and NGLs averaged 237 000 m^3/d in 1993, up by 3% or 7 000 m^3/d from the previous year (see Figure 5.1.3). Almost half the increase went to the U.S. where the demand for Canadian crude oil is increasing as U.S. domestic production declines. Deliveries to the U.S. rose by 3 000 m^3/d to 121 000 m^3/d. Deliveries also rose in Ontario by 2 000 m^3/d to 84 000 m^3/d but were unchanged in the Prairies.

Figure 5.1.3
IPL Deliveries
000 m^3/d



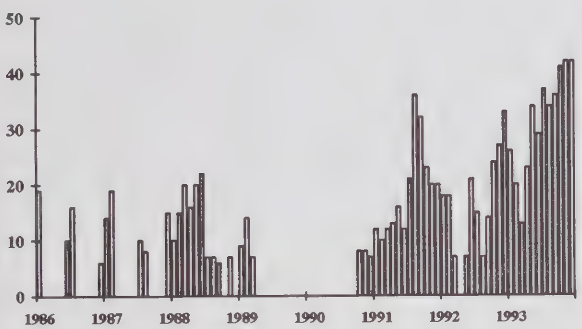
5.2 Apportionment

Pipeline apportionment is normally required when shippers' crude oil nominations exceed the pipeline's capacity to deliver the nominated volumes. Apportionment is, in effect, an alternative to the price mechanism for allocating pipeline space when nominal or actual demand for pipeline space exceeds supply. The price mechanism is precluded as a rationing device because the Canadian pipeline industry is regulated by the NEB which fixes pipeline tolls

on a cost of service basis (i.e. on the basis of anticipated throughput, tolls are set just high enough to cover the pipeline's fixed and variable costs and allow a reasonable rate of return on equity).

Except for April 1992, IPL has consistently had to apportion pipeline space in every month since October 1990, as shown in Figure 5.2.1. Since western producers cannot guarantee delivery of all their crudes when facing apportionment, they have been offering price discounts as compensation to those refiners served by IPL. They have also had to divert crude to secondary or spot markets where netbacks have traditionally been lower, and, sometimes have shut in crude at the well head. Although it is difficult to estimate the cost of apportionment since other factors are at play, some industry analysts estimate that the Canadian upstream sector lost over $300 million in revenues in 1993. In the downstream sector, apportionment complicates refinery operations.

Figure 5.2.1
IPL Apportionment
%



The reappearance of apportionment over the last three years has coincided with a growing excess supply of domestic crude oil. Western Canadian crude oil production is now about 25 000 m^3/d higher than three years ago while refinery demand in western Canada has fallen by about 5 000 m^3/d, mainly reflecting the recession. This has put increasing pressure on the IPL system, specifically that part serving refineries in the U.S. Great Lakes region. IPL deliveries to U.S. refineries have risen by almost 30 000 m^3/d over the same period. It is worth noting that overnominations have not prevented IPL from generally maintaining throughput close to its available capacity; and that apportionment has, so far, not been a chronic problem for the other Canadian pipelines serving less profitable markets.

Notwithstanding the rising excess supply of domestic crude, a large part of the apportionment problem has stemmed from shippers anticipating apportionment, and inflating their nominations accordingly in an attempt to reserve line space. An industry working committee made up of IPL and producer representatives has developed elaborate nomination and verification procedures that were intended to identify and penalize shippers who were inflating their nominations. However, these procedures have not been particularly effective in mitigating overnominations by shippers. In fact, in the last few months of 1993, apportionment levels reached record levels of over 40%.

5.3 Expansion Plans

IPL

A steady increase in western Canadian crude oil production since the fall of 1990 and the situation of chronic apportionment prompted IPL to apply to the NEB for a 27 000 m^3/d capacity expansion. The proposal received broad industry support and was approved by the NEB in January 1994. With the expansion scheduled to be completed by the end of 1994, producers hope to avoid the costs of shut-in production, and to reduce the current price discounting of Canadian crude oil in U.S. Midwest markets. It is estimated that Canadian producers have had to discount their crude by as much as a $1 U.S. per barrel during the last two years because of the perceived unreliability of IPL deliveries.

The expansion's primary target markets are the existing customers in and around the Chicago refining area. The $430 million capital cost of

the project includes $256 million to expand the western Canadian system. The remainder will be spent expanding the affiliated Lakehead system in the United States. The Canadian portion of the expansion will involve the laying of about 500 km of 20-inch diameter pipe, the reactivation of 534 km of existing pipe and the installation of eight new pumping stations and four storage tanks. In the U.S., Lakehead will install 220 km of 20-inch pipeline, additional pumps and three storage tanks. The expansion will add about five cents per barrel to the current $1.35/bbl tolls from Edmonton to Sarnia.

TMPL

In late 1993, Trans Mountain, which has been the principal recipient of the IPL overflow, also applied for a pipeline expansion. The project was approved by the NEB in late April 1994. The $28 million expansion will permit TMPL to ship an additional volume of 6 000 m^3/d. The target markets for the expansion are the seven Puget Sound refineries in Washington State. Because the increase in throughput is large relative to the small capital costs involved, tolls from Edmonton to Vancouver are expected to decline to about $1.32 per barrel from the current rate of $1.51.

The InterCoastal Natural Gas Pipeline Project

The Ontario refining sector has the capacity to process almost 83 000 m^3/d of crude oil with about two-thirds or almost 53 000 m^3/d of this capacity located in Sarnia. IPL Lines 7 and 8 serve the refineries east of Sarnia (which include the two remaining Toronto area refineries, as well as a 10 000 m^3/d United refinery in Warren, Pennsylvania which heavily depends on western Canadian crude supply). Both lines have throughput capacities of over 40 000 m^3/d each. Hence, there exists considerable excess pipeline capacity on this part of the IPL system.

In order to more fully use the pipeline assets east of Sarnia, IPL applied to the NEB in mid-1993 to convert Line 8 from a low pressure oil line to a higher pressure natural gas pipeline in a joint venture with ANR Pipeline Company of Detroit, Michigan (with Line 7 left to supply the refineries). The joint venture was to be operated under a new company, InterCoastal Pipe Line Inc, with IPL holding an 80% equity interest.

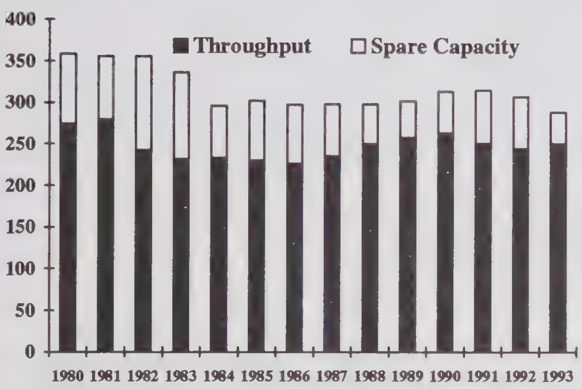
The $46 million project would have increased Ontario's access to the U.S., as well as Canadian, natural gas supply. Two short pipelines were to be built to connect Line 8 to ANR's existing underground storage and related pipeline facilities on the U.S. side near Sarnia. From there, natural gas was to be delivered to the outskirts of Toronto where it would connect with the Consumers Gas distribution system in which IPL acquired an 85% interest. However, in late April 1994, the NEB denied the InterCoastal application, for reasons mainly relating to concerns about the safety of the conversion of line 8 to natural gas service.

6. Refinery Activity

6.1 Refinery Rationalization

Canadian refinery rationalization continued during 1993 with the closure of two small British Columbia refineries and the conversion of an Ontario refinery to specialty product production.

Figure 6.1.1
Refinery Utilization vs Capacity in Canada
000 m³/d



In B.C., the Shell Burnaby[1] and the Petro-Canada Port Moody refineries were both closed by mid-1993 and converted to receive finished product from Edmonton through the Trans Mountain pipeline. These refinery closures removed 7 780 m³/day of refining capacity in western Canada and will increase the utilization of the more efficient Edmonton area refineries. Also during 1993, Esso Petroleum announced that it will close its Ioco, B.C. refinery by mid-1994, leaving only the Chevron (Burnaby) and Husky (Prince George), refineries operating in B.C.

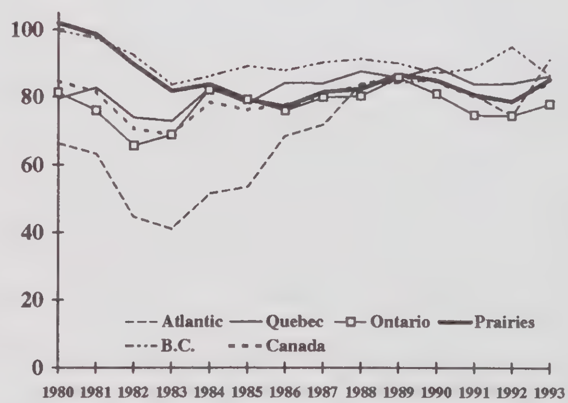
In Ontario, Petro-Canada converted its Mississauga refinery to produce lubricating oils using feedstocks produced in its Oakville refinery, thus integrating the operations of two refineries completely and removing 9 530 m³/day of crude distillation capacity from Ontario.

Figure 6.1.1 illustrates refinery throughput and capacity in Canada from 1980 to 1993. While refinery throughput increased in 1993 from 1992, it remained below the level of refinery throughput in 1990 and 23 000 m³/day lower than the highest level of refinery throughput in 1981.

Across Canada, refinery utilization increased from 80% in 1992 to 84% in 1993. The increase in refinery utilization was a result of an increase in refinery throughput and a decrease in refinery capacity. Total refinery throughput averaged 251 100 m³/day in 1993, up almost 6 300 m³/day from the 1992 throughput.

Figure 6.1.2 shows the trends in refinery utilization rates on a regional basis from 1980 to 1993. The largest increase in regional throughput was in Atlantic Canada, where there were increased product exports.

Figure 6.1.2
Regional Refinery Utilization Rates
%



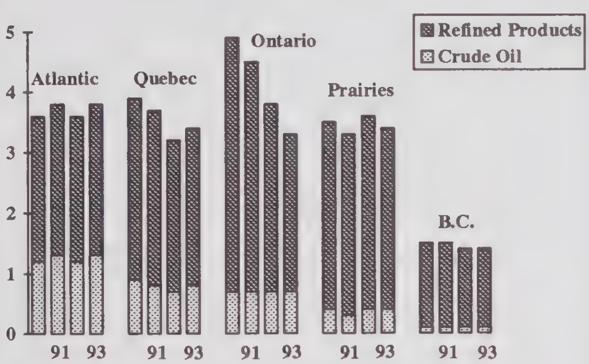
[1] Appendix VI "Refining Capacity in Canada" provides a list of refineries operating in Canada as of December 31, 1993.

7. Crude Oil and Petroleum Product Stocks

Total crude oil and refined petroleum products held by refineries and major distributors totalled 11.9 million m^3 at the end of 1993. This level was down almost 0.5 million m^3 or 4% from 12.5 million m^3 recorded a year earlier. Of this volume, product stocks at 9.6 million m^3 were down 0.2 million m^3 or 2%. Crude oil stocks, were down 0.3 million m^3 or 11% to 2.3 million m^3.

As illustrated in Figure 7.1.1, stocks have been on the decline in recent years. This can be attributed to a number of factors, most notably a decline in refined product demand. This trend has been exacerbated by several refinery closures, the recession, and improvements in inventory management methods.

Figure 7.1.1
Crude Oil and Petroleum Product Stocks
million m^3

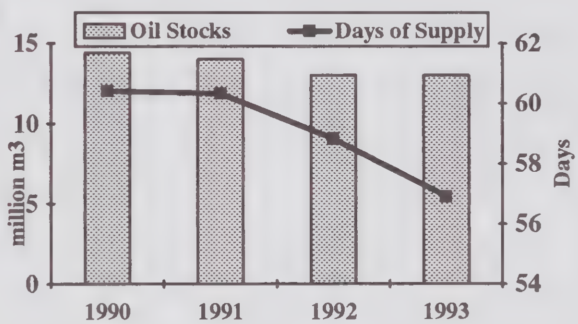


End-1993 stocks of refined petroleum products increased marginally in the Atlantic region, Quebec and British Columbia from the year before. A large decrease in Ontario and a smaller one in the Prairies offset the increases elsewhere. Ontario recorded the largest volumetric decrease, down 273 000 m^3 or 12% to 2.1 million m^3.

The decline in stocks mainly fell on 'other' products. Stocks of main petroleum products including motor gasoline, middle distillates and heavy fuel oil actually rose by 1% to 7.1 million m^3, (representing about 39 days of supply).

At the end of 1993, oil and refined product stocks represented about 56 days[1] of demand (see Figure 7.1.2).

Figure 7.1.2
Days of Consumption



[1] Stocks do not include crude oil held in pipeline tankage. If these stocks were included in the calculation, the number of days of supply would increase by about 7 days.

8. Crude Oil Prices

8.1 Market Developments

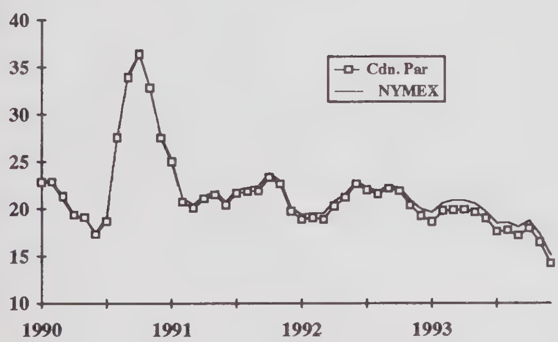
Prices of Canadian crude oil are mainly influenced by international supply and demand fundamentals and to a lesser extent by local market conditions. In 1993, the world crude oil market was plagued by OPEC's inability to control members' production, and weak demand by major oil-consuming nations. These factors, combined with an unexpected surge in North Sea production, resilient Russian exports and the potential resumption of exports from Iraq helped to push the price of crude oil down to its lowest level in years.

Canadian crude oil prices tend to track West Texas Intermediate (WTI), the benchmark crude for the valuation of North American production. WTI traded on the New York Mercantile Exchange about 10% or US $2.14/bbl below a year earlier. By year-end, WTI had tumbled briefly below the US $14.00/bbl mark, the lowest level since the fourth quarter 1988.

8.2 Domestic Crude Oil Postings

The Canadian equivalent light sweet crude, posted by four major refiners at Edmonton, slipped 7% or $10.79/m^3$ to a five-year low of $137.22/m^3$ (US $16.94/bbl). The Canadian Par price fell from an April high of $148.27/m^3$ to a December low of $109.00/m^3$. However, prices did not fall steadily downwards, as OPEC squabbling, fleeting market optimism and weather conditions resulted in price spikes of as much as $7/m^3$.

Figure 8.2.1
Light Crude Oil Prices
US$/bbl



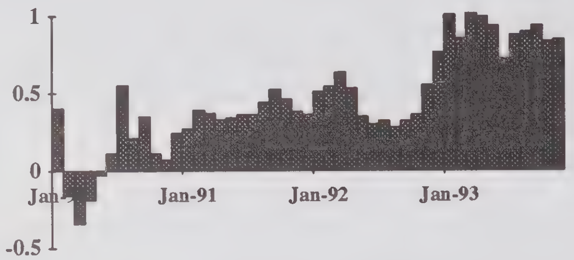
Canadian Par crude remained relatively stable at around $145.00 /m^3$ through the first half of the year before slipping below $140.00/m^3$ in early summer. Most of the price drop since the April high occurred following OPEC's late September and early November meetings which reaffirmed its 24.5 million barrel output ceiling, but failed to stem members' over-production. While prices rallied briefly prior to the September meeting, Canadian Par crude subsequently fell nearly $24.00/m^3$ accounting for almost three quarters of the decline since April.

During 1993, Canadian heavy crude oil prices, supported by strong upgrader demand, fared much better than light crude. Heavy crude oil prices, posted at Hardisty, recorded a significantly smaller price decline from 1992 than did light crude. Heavy crude postings averaged $106.11/m^3$ (US $13.09/bbl), down about 3% or $2.74/m^3$ from 1992.

8.3 Crude Oil Price Differentials

The Canadian heavy to light crude oil price differential narrowed to $31.11/m^3$ in 1993 from $39.16/m^3$ in 1992 and $51.42/m^3$ in 1991. The differential usually narrows during the summer months as a result of higher demand for heavy crude for the production of asphalt. However, since 1991, the differential has narrowed substantially due to the installation of additional heavy crude upgrading capacity at Billings, Montana and the November 1992 start-up of the Husky Bi-provincial upgrader.

Figure 8.3.1
Differential (WTI-Cdn Par)
US$/bbl



On the international scene, Canadian Par crude delivered to Chicago has been trading at a discount of US $0.87 below WTI. This differential is normally influenced by such factors as refinery yield and the value of other competing crudes in the same market. However, the discount has been most notably affected by delivery concerns. It has been widely reported that some Canadian crudes are being further discounted in the key Chicago market by as much as US $0.50 to $1.00/bbl due to the impact of high apportionment on the Interprovincial Pipe Line system.

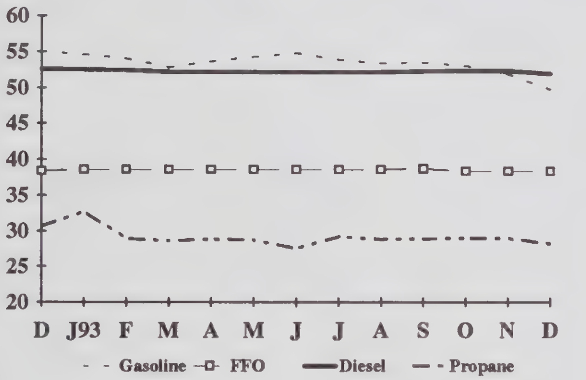
A declining Canadian dollar cushioned the impact of lower international crude oil prices on western Canadian producers. Nevertheless, lower prices mitigated revenue gains from higher than expected production in 1993 and resulted in the postponement or cancellation of some higher-cost heavy oil projects such as Phase 9 and 10 of Imperial Oil's 15 000 m^3/day project at Cold Lake. Amoco Canada has also reconsidered the timing of its 8 000 m^3/day Primrose heavy oil proposal near Cold Lake, which the company hoped to get underway in late 1994.

9. Refined Petroleum Product Prices

9.1 Price Trends

Petroleum product prices were generally stable through 1993, with some downward price movement occurring in the fourth quarter. Regular gasoline prices began to drop in November and by December, at 49.8 ¢/l, were at their lowest level since 1989 (see Figure 9.1.1).

Figure 9.1.1
Average Canadian Retail Prices in Major Centres
¢/l

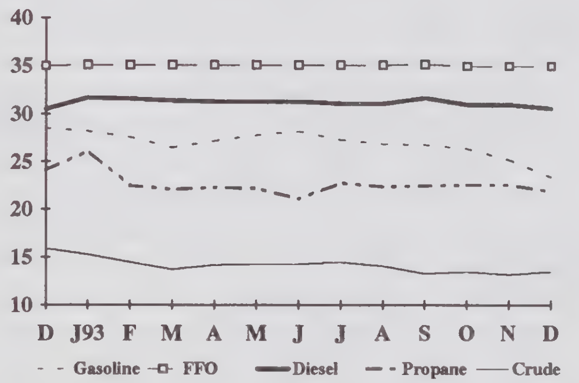


Diesel prices followed a similar pattern, although to a lesser degree. December 1993 furnace fuel oil (FFO) prices were unchanged from a year earlier. On an ex-tax basis, regular gasoline prices were the lowest among the four products surveyed (see Figure 9.1.2).

In December 1993, the monthly average regular gasoline prices in all ten major Canadian cities surveyed experienced sharp reductions compared to December 1992 prices. The largest price reductions were in eastern Canada, where the markets have been traditionally more stable, with higher prices than in the west. In St. John's, Newfoundland, the price decline had been underway since July with a drop of almost 8 ¢/l over the period July to December 1993. Charlottetown, the only regulated market, experienced a price drop during December. At 54.5 ¢/l, the average December 1993 price for regular gasoline in Charlottetown was 5.6 ¢/l lower than the December 1992 price.

During the last half of 1993, regular gasoline prices in Halifax fell 5.4 ¢/l, and in November, despite a tax increase that came into effect in

Figure 9.1.2
Average Canadian Ex-Tax Retail Prices in Major Centres
¢/l



October, the price was 47.2 ¢/l, the lowest price observed in eastern Canada since 1987. In July 1991, the Government of Nova Scotia removed all petroleum product price controls and eliminated barriers to entry into gasoline and diesel fuel retailing, leaving the way open to the introduction of self-serve stations. The falling prices which have been observed during the past year in Nova Scotia are a direct result of increased competition in the marketplace.

Of all major cities surveyed across Canada, Montreal recorded the largest price drop (7.3 ¢/l) during the December 1992 to December 1993 period.

In 1993, diesel prices remained lower than gasoline prices throughout the year until December, when the gasoline price dipped. The average monthly diesel price was 0.6 ¢/l lower in December 1993 compared to December 1992. At year-end, the Atlantic provinces recorded reduced diesel prices, pushing the Canadian monthly average down to 52 ¢/l in December, the closest it has come to the pre-Gulf war price of 51 ¢/l in 1990.

Average Canadian FFO prices remained unchanged at 38.4 ¢/l in December 1993 compared to December 1992. St. John's, Newfoundland, experienced a significant price reduction (4.3 ¢/l) in December 1993 over December 1992. This was countered mostly by price increases in Toronto and Winnipeg during the last quarter of the year. Halifax recorded the lowest FFO price in the country, 35.7 ¢/l, in December 1993.

Propane prices rose sharply in January 1993 to 32.7 ¢/l, from the 1992 December price of 30.6 ¢/l. Price volatility in propane is to be expected due to its seasonal demand. Tight supply, brought about by the late crop drying season in the U.S. mid-west in the fall of 1992, increased propane market pressures. As a result, many of the western markets experienced high propane prices in January. Propane prices were lowest in June, averaging 27.5 ¢/l. A comparison of December 1993 versus December 1992 indicates that 1993 ended with a lower propane price (28.2 ¢/l) than 1992, largely due to a significant decline in Charlottetown and Vancouver.

Whereas the rate of price increase of all consumer goods was 20% between 1988 and 1993, regular gasoline prices increased by only 8.5% over the period.

Figure 9.1.3
Actual vs Deflated (1988) Regular Gasoline Prices
¢/l

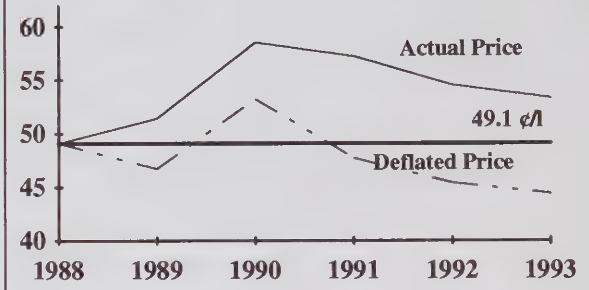


Figure 9.1.3 illustrates actual regular gasoline prices over the last five years versus prices deflated to 1988 dollars. Except in 1990, when prices peaked as a result of the Gulf war, deflated prices of regular gasoline have been consistently lower than the average 1988 price for regular gasoline, 49.1 ¢/l. Once corrected for inflation, the average retail price of gasoline was 4.7 ¢/l lower in 1993 than what it was in 1988. Although not shown on the graph, the deflated ex-tax price in 1993 is 22.3 ¢/l, 7 ¢/l lower than the 1988 price.

9.2 Cost Components of Regular Gasoline

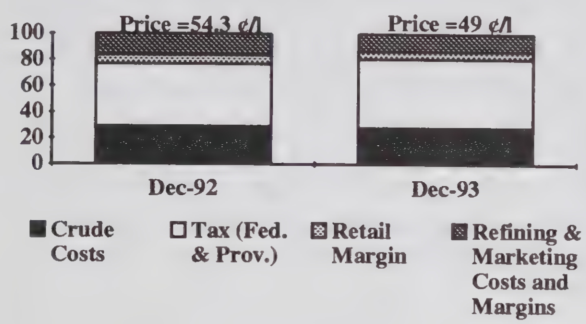
In today's deregulated environment, crude oil costs are only one component influencing the level of refined product prices. Other factors include the cost of refining, distributing and marketing the products, federal and provincial taxes and refiner and dealer margins. Nevertheless, local market conditions are perhaps the most important determinant of product prices in the short run. Changes in product availability, inventory levels and demand can significantly influence the level of product prices.

The average Canadian crude cost component of regular gasoline dropped steeply from 15.3 ¢/l in January to 13.5 ¢/l in December. The largest price decrease, 1.6 ¢/l, occurred during the first three months of the year, followed by a period of stability until August. An abrupt price drop, from 14.1 ¢/l in August to 13.3 ¢/l in September, lowered the crude cost component for the rest of the year. The monthly average crude cost was 13.5 ¢/l in December 1993, 2.4 ¢/l lower than the 1992 December average. Crude costs accounted

for 28% of the average retail price in 1993, vis-a-vis 29% in 1992 (Figure 9.2.1).

Federal and provincial taxes together accounted for 53% of the retail price in December 1993, up 5% from the previous December. With the increase in the provincial tax component offsetting the decrease in the federal tax component, the higher proportion of tax to retail price was mainly due to the lower retail price in December 1993.

Figure 9.2.1
Cost Components of Regular Gasoline
%



Retail margins were relatively stable during the year, fluctuating between 3.1 ¢/l and 3.6 ¢/l. The residual component, refining and marketing costs and margins, also showed very little change in 1993, until November when it dropped to 8.1 ¢/l from 11.2 ¢/l in October. This component represents the portion of the retail price that is available (after deducting crude costs, federal and provincial taxes and retail margins) to cover refining, marketing, transportation and distribution costs and provide a return on investment. However, this residual revenue may not always be sufficient to recover all costs.

9.3 Consumption Taxes on Petroleum Product

There were no significant changes in the petroleum product consumption taxes in 1993. Federal excise taxes on gasoline and diesel remained unchanged at 8.5 ¢/l and 4 ¢/l, respectively. The other component of the federal tax, the GST, is based on 7% of the retail price. Reflecting the retail price decrease in 1993, the average GST on regular gasoline was 3.1 ¢/l by December, 0.3 ¢/l lower than in December 1992.

The average month-end provincial tax on regular gasoline increased to 14.4 ¢/l in December 1993, from 14.0 ¢/l in December 1992. The bulk of this increase was registered in the last two quarters of 1993. For diesel, the average month-end provincial tax increased by 0.5 ¢/l to 14.0 ¢/l in December 1993 over the same month last year. Provincial tax increases in Nova Scotia, Saskatchewan and British Columbia account for the higher provincial tax for diesel this year. Saskatchewan, Nova Scotia and Prince Edward Island increased their tax on automotive propane in 1993, causing the average month-end provincial tax in December 1993 to increase to 4.6 ¢/l from 4.5 ¢/l a year earlier.

Under the British Columbia Motor Fuel Tax Act, the transit tax was extended to the Victoria Regional Transit Service Area. Effective May 1, 1993, it was 1.5 ¢/l on both gasoline and diesel. In addition, the existing transit tax in the Vancouver Regional Transit Service Area was increased from 3 ¢/l to 4 ¢/l on July 1, 1993. As well, provincial taxes of 11 ¢/l on gasoline and 11.5 ¢/l on diesel (which include a 1 ¢/l increase for both products as of September 1, 1993) is currently levied in B.C.

9.4 Price Differentials

In the ten major Canadian centres, retail gasoline price differentials generally continued to widen during 1993 with the premium vs regular gasoline price spread increasing more than the mid-grade vs regular price differential. Among the three grades, competition is strongest on regular unleaded gasoline, the grade with the highest sales. The price of this grade is usually the only one posted. Increasing the price of the higher grades is one strategy used by gasoline retailers to maximise their overall revenue. The effect is an increase in the price differential between the regular and the higher grades.

The end-December 1993 premium vs regular gasoline price differentials ranged from 4.3 ¢/l in Charlottetown, the only market where prices are regulated, to 9.3 ¢/l in Montreal. Differentials in the remaining eight markets were between 7.1 ¢/l and 8.8 ¢/l. The largest year-over-year increase in the price differential was recorded in Charlottetown (+1.9 ¢/l) and the smallest increase was in Regina (+0.4 ¢/l).

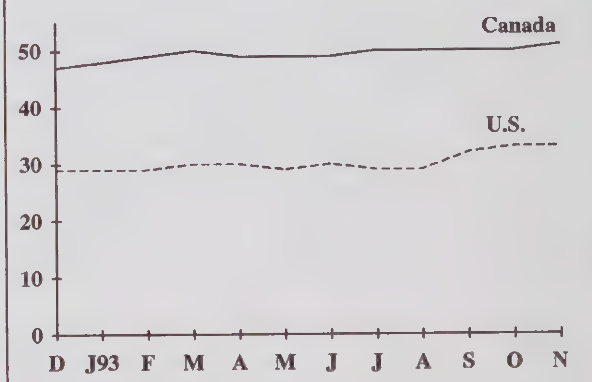
9.5 Canada versus the U.S.

Over the 12-month period ending November 1993, the average retail price of gasoline (all grades) experienced a greater decline in Canada than in the U.S.. In Canada, the price ranged from a high of 56.4 ¢/l in January to 53.9 ¢/l in November, the lowest average price recorded since March 1989. In Canadian currency, the highest U.S. average retail price was about 42 ¢/l in October, while the lowest was 38 ¢/l in March.

The differential between the average prices in Canada and the U.S. was reduced from 16.1 ¢/l in November 1992 to 12.9 ¢/l in November 1993. Much of this narrowing was attributable to the weakened Canadian dollar, as the exchange rate rose from 1.2680 to 1.3177. The exchange rate accounted for about 50% of the 3.2 ¢/l decline in the differential between the two countries.

In both countries, average consumption taxes remained fairly stable, with some increases in the last quarter of the period. As Figure 9.5.1 highlights, taxes in Canada account for 50% of the retail price, while in the U.S. about 30% of the retail price is attributed to tax. The tax component of the retail price increased in both countries during the year. In Canada, this was largely due to declining retail prices. In the U.S., additional federal taxes levied in October 1993 contributed to the increase.

Figure 9.5.1
Tax as a Percentage of Retail Price
%



While the retail prices and taxes in the U.S. remained lower than those in Canada, gasoline prices in Canada are generally lower than in most other International Energy Agency member countries.

9.6 Structural Changes

The rationalization of the retail gasoline market continued in 1993. A survey conducted by 1,100, or about 6% of the retail gasoline stations across Canada since September 1992. In the past two years there has been increased publicity about the rationalization plans of the major refiner-marketers, Imperial Oil, Petro-Canada and Shell. Their programs are aimed at reducing costs of operation through refinery and retail outlet closures and staff reductions. These companies closed 11% of their outlets between 1992 and 1993. The regional refiner-marketers, Chevron, Irving, Sunoco, Ultramar, Co-op and Husky, are also rationalizing their networks and closed about 6% of their stations. In contrast to the major and regional refiner-marketers, the independent retailers increased the number of their retail outlets by 3.4% and now operate almost 20% of all gasoline stations in Canada.

Increased gasoline demand, coupled with a reduction in the number of retail gasoline outlets, resulted in higher average throughputs at gasoline stations. The majors posted the best gains in terms of daily throughput per service station, reflecting the results of their rationalization program. Overall, the average daily throughput per station in Canada rose to 4.9 thousand litres per day in 1993, from 4.3 thousand litres per day during 1992. Even though this is an improvement, the average daily volumes per service station in the U.S. are still much higher, more than twice that of an average Canadian outlet.

Market share shifted from 1992 to 1993, showing gains for the independents, at the expense of the majors. The major retailers' market share was reduced from 54% in 1992, to 52% in 1993. Independents had 19% of the market share in 1993, while the share of the regional retailers remained unchanged at 29%.

APPENDICES

Appendix I: Production of Crude Oil and Equivalent

	1991 Year	1992 Year	1993 1Q	1993 2Q	1993 3Q	1993 4Q	1993 Year
		000 m³/d					
A. Light and Equivalent							
Conventional							
Alberta	112.2	114.5	116.9	115.0	116.1	113.5	115.4
B.C.	5.5	5.6	5.5	5.1	5.5	5.8	5.5
Saskatchewan	11.4	11.7	12.2	12.2	13.0	13.9	12.9
Manitoba	1.9	1.8	1.7	1.7	1.7	1.8	1.8
NWT	5.2	5.2	4.7	5.3	5.4	4.8	5.1
Ontario	0.6	0.6	0.6	0.7	0.7	0.,8	0.8
Nova Scotia	0.0	1.7	0.0	2.0	5.4	3.6	2.8
Total	**136.5**	**141.1**	**141.6**	**142.0**	**147.8**	**144.2**	**144.3**
Synthetic							
Suncor	9.6	8.9	9.0	7.6	11.3	10.1	9.5
Syncrude	26.3	28.3	23.0	30.6	30.4	32.4	29.1
Total	**35.9**	**37.2**	**32.0**	**38.2**	**41.7**	**42.5**	**38.6**
Pentanes Plus(excl. diluent)	**8.6**	**8.0**	**8.7**	**8.9**	**11.2**	**8.2**	**9.3**
Total Light	**179.3**	**186.3**	**182.3**	**189.1**	**200.7**	**194.9**	**192.2**
B. Heavy Crude							
Alberta							
Conventional	30.6	30.4	32.8	33.3	34.9	35.3	34.1
Bitumen	19.5	19.9	20.4	21.9	22.1	19.0	20.9
Diluent	9.3	10.2	10.8	10.6	9.2	13.0	10.9
Total	**59.4**	**60.5**	**64.0**	**65.8**	**66.2**	**67.3**	**65.9**
Saskatchewan							
Conventional	22.3	24.7	25.8	26.2	28.6	28.9	27.4
Diluent	3.1	3.4	3.6	3.0	3.4	4.3	3.6
Total	**25.4**	**28.1**	**29.4**	**29.2**	**32.0**	**33.2**	**31.0**
Total Heavy	**84.8**	**88.6**	**93.4**	**95.0**	**98.2**	**100.5**	**96.9**
C. Total Production	**264.1**	**274.9**	**275.7**	**284.1**	**298.9**	**295.4**	**289.1**

Appendix II: Supply and Disposition of Crude Oil and Equivalent

	1991	1992	1993				
	Year	Year	1Q	2Q	3Q	4Q	Year
		000 m^3/d					
A. Light and Equivalent							
Supply							
Production	179.4	186.0	182.3	189.2	200.7	195.0	191.9
Plus: Upgraders	2.0	4.7	9.6	7.2	8.6	10.1	8.9
Statistical Diff.	8.1	7.3	8.9	1.8	3.5	9.5	6.0
Net Supply	**189.5**	**198.0**	**200.8**	**198.1**	**212.8**	**214.7**	**206.9**
Domestic Demand							
Atlantic	0	0.6	1.3	1.5	2.8	2.4	2.0
Quebec	2.7	0.4	0.0	0.8	1.7	1.0	0.9
Ontario	58.8	57.9	56.2	57.1	56.4	61.8	57.9
Prairies	46.6	42.9	44.3	41.9	49.7	47.4	45.9
B.C.	18.9	20.6	20.9	13.2	13.1	11.0	14.6
Total	**127.0**	**122.1**	**122.7**	**114.5**	**123.7**	**123.6**	**121.2**
Exports	**62.4**	**75.9**	**78.1**	**83.7**	**89.1**	**91.1**	**85.5**
Total Demand	**189.4**	**198.0**	**200.8**	**198.2**	**212.8**	**214.7**	**206.7**
B. Heavy Crude (Blended)							
Supply							
Production	84.7	88.3	93.4	95.0	98.3	100.6	96.9
Recycled Diluent	1.0	1.3	2.2	2.4	2.5	1.9	2.3
Less: Upgrader Feedstock	0	2.1	7.0	8.0	7.6	9.0	7.9
Statistical Diff.	(5.0)	(7.9)	(4.7)	(11.1)	(3.5)	(9.7)	(7.3)
Net Supply	**80.7**	**79.6**	**83.9**	**78.3**	**89.6**	**83.8**	**84.0**
Domestic Demand							
Atlantic	0	0	0	0	0	0	0
Quebec	0.1	0	0	0	0	0	0
Ontario	10.2	9.7	13.4	10.5	9.4	6.9	10.1
Prairies	10.3	11.3	12.6	9.8	12.9	11.9	11.8
B.C.	0.6	0.8	0.9	1.4	0.7	0.1	0.8
Total	**21.1**	**21.5**	**26.9**	**21.7**	**23.0**	**18.9**	**22.7**
Exports	**59.6**	**58.1**	**57.0**	**56.6**	**66.6**	**64.9**	**61.3**
Total Demand	**80.7**	**79.6**	**83.9**	**78.3**	**89.6**	**83.8**	**84.0**

Appendix III: Crude Oil Exports by Destination

		1991 Year	1992 Year	1993 1Q	1993 2Q	1993 3Q	1993 4Q	1993 Year
				000 m³/d				
U.S. PADD								
I	Light	7.2	7.9	7.9	9.7	8.6	7.7	8.5
	Heavy	1.3	1.4	2.2	2.5	2.0	2.1	2.2
	Total	**8.5**	**9.3**	**10.1**	**12.2**	**10.6**	**9.8**	**10.7**
II	Light	41.9	50.9	49.9	52.2	55.2	57.6	53.8
	Heavy	51.8	52.0	49.3	48.0	56.6	56.9	52.7
	Total	**93.7**	**102.9**	**99.2**	**100.2**	**111.8**	**114.5**	**106.5**
III	Light	0	1.0	0	0.4	2.7	2.1	1.3
	Heavy	1.5	0	0	0	0	0.4	0.1
	Total	**1.5**	**1.0**	**0**	**0.4**	**2.7**	**2.5**	**1.4**
IV	Light	11.1	10.7	10.4	10.9	10.7	10.5	10.6
	Heavy	3.0	4.2	5.5	5.7	6.9	5.5	5.9
	Total	**14.0**	**14.9**	**15.9**	**16.6**	**17.6**	**16.0**	**16.5**
V	Light	1.3	3.5	9.3	10.2	11.8	12.6	11.0
	Heavy	0.5	0.3	0.1	0.3	1.1	0.1	0.4
	Total	**1.8**	**3.8**	**9.4**	**10.5**	**12.9**	**12.7**	**11.4**
Total U.S.	Light	61.5	74.0	77.5	83.4	89.0	90.5	85.2
	Heavy	58.0	57.9	57.1	56.5	66.6	65.0	61.3
	Total	**119.5**	**131.9**	**134.6**	**139.9**	**155.6**	**155.5**	**146.5**
Offshore	Light	0.6	1.7	0.3	0.4	0	0.7	0.4
	Heavy	1.4	0.2	0	0	0	0	0
	Total	**2.0**	**1.9**	**0.3**	**0.4**	**0**	**0.7**	**0.4**
Total	Light	62.1	75.7	77.8	83.8	89.0	91.2	85.6
	Heavy	59.4	58.1	57.1	56.5	66.6	65.0	61.3
	Total	**121.6**	**133.8**	**134.9**	**140.3**	**155.6**	**156.2**	**146.9**

Appendix IV: Pipeline Deliveries

	1991 Year	1992 Year	1993 1Q	2Q	3Q	4Q	Year
		000 m³/d					
A. Trans Mountain Pipe Line (TMPL)							
Domestic Deliveries							
Crude & Semi Refined Prod.	21.2	23.0	22.0	15.1	17.9	18.8	18.4
Refined Products	2.5	2.6	3.0	2.8	3.7	2.8	3.0
Total	23.7	25.6	25.0	17.9	21.6	21.6	21.4
Foreign Deliveries							
Tankers	4.0	3.8	3.1	1.9	2.4	2.3	2.4
Puget Sound Area	1.1	2.8	6.7	8.7	10.9	10.4	9.1
Total	5.1	6.6	9.8	11.3	13.3	12.7	11.6
Total TMPL	**31.4**	**32.2**	**34.8**	**29.2**	**34.9**	**34.3**	**33.1**
B. Interprovincial Pipe Line (IPL)							
Domestic Deliveries							
Light Crude	74.1	69.0	70.0	68.9	69.2	71.8	70.1
Heavy Crude	13.8	10.0	18.3	14.4	15.8	14.2	15.7
Other[1]	27.2	34.9	31.9	28.9	31.3	31.4	30.9
Total	115.1	113.9	120.2	112.2	116.3	117.4	116.7
Foreign Deliveries							
Light Crude	49.5	58.0	57.6	59.8	63.0	64.6	61.2
Heavy Crude	53.2	53.3	51.5	50.6	58.4	58.1	54.7
Other[2]	6.7	5.8	4.7	4.0	4.7	4.8	4.6
Total	109.4	117.1	113.8	114.4	126.1	127.5	120.5
Total IPL	**224.5**	**231.0**	**234.0**	**226.6**	**242.4**	**244.9**	**237.2**
C. Pipelines to Montreal							
IPL Deliveries							
To Montreal	2.4	0	0	1.7	1.5	1.5	1.2
For Export/Transfer	0	0	0	0	0	0	0
Total IPL	2.4	0	0	1.7	1.5	1.5	1.2
Portland-Montreal							
Montreal Imports[3]	25.0	26.5	30.3	24.4	29.2	30.0	28.5
Total Montreal Receipts	**27.4**	**26.5**	**30.3**	**26.1**	**30.7**	**31.5**	**29.7**

[1] Includes Petroleum Products and NGLs.
[2] Includes Petroleum Products and NGLs and some U.S. domestic crudes delivered to the U.S.
[3] May include cargos imported directly into Montreal.

Appendix V: Canadian Refinery Receipts

	1991 Year	1992 Year	1993 1Q	2Q	3Q	4Q	Year
		000 m^3/d					
A. Domestic Receipts							
Light & Equivalent							
Atlantic	0	0.5	1.3	1.5	2.8	2.5	2.0
Quebec	0	0.4	0	0.8	1.7	1.0	0.9
Ontario	58.9	57.8	56.3	57.1	56.5	61.7	57.9
Prairies	46.7	42.8	44.2	41.9	49.8	47.4	45.9
B.C.	18.8	20.6	20.9	13.2	13.1	11.0	14.5
Total	**124.4**	**122.1**	**122.7**	**114.5**	**123.9**	**123.6**	**121.2**
Heavy							
Atlantic	0	0	0	0	0	0	0
Quebec	0	0	0	0	0	0	0
Ontario	10.2	9.6	13.3	10.5	9.4	6.9	10.0
Prairies	10.2	11.2	12.6	9.8	12.9	11.9	11.8
B.C.	0.6	0.8	0.9	1.4	0.7	0.1	0.8
Total	**21.0**	**21.6**	**26.8**	**21.7**	**23.0**	**18.9**	**22.6**
Other (incl. partially processed)							
Atlantic	0	0	0	0	0	0	0
Quebec	0.1	0	0	0.1	0.3	0.4	0.2
Ontario	4.5	4.8	4.7	3.7	4.4	3.9	4.1
Prairies	3.9	2.9	3.2	1.8	3.3	4.3	3.1
B.C.	4.1	2.8	1.9	0.2	0.3	0.5	0.7
Total	**12.9**	**10.5**	**9.8**	**5.8**	**8.3**	**9.1**	**8.1**
Total Domestic Receipts							
Atlantic	0.3	0.5	1.3	1.5	2.8	2.5	2.0
Quebec	0.1	0.4	0	0.9	2.0	1.4	1.1
Ontario	73.6	72.2	74.3	71.3	70.3	72.5	72.0
Prairies	60.8	56.9	60.0	53.5	66.0	63.6	60.8
B.C.	23.5	24.2	23.7	14.8	14.1	11.6	16.0
Total	**158.3**	**154.2**	**159.3**	**142.0**	**155.2**	**151.6**	**151.9**
B. Crude Oil Imports							
Atlantic	49.7	44.4	54.7	50.9	51.4	53.3	52.6
Quebec	41.9	43.8	48.6	37.3	45.5	48.8	45.1
Ontario	0.4	0.5	0.3	0	2.4	0	0.7
Prairies	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	0	0
Total	**92.0**	**88.7**	**103.6**	**88.2**	**99.3**	**102.1**	**98.4**
C. Total Receipts							
Atlantic	50.0	44.9	56.0	52.4	54.2	55.8	54.6
Quebec	42.0	44.2	48.6	38.2	47.5	50.2	46.2
Ontario	74.0	72.7	74.7	71.3	72.7	72.5	72.7
Prairies	60.8	56.9	60.0	53.5	66.0	63.6	60.8
B.C.	23.5	24.2	23.7	14.8	14.1	11.6	16.0
Total	**250.3**	**242.9**	**263.0**	**230.2**	**254.5**	**253.7**	**250.3**

Appendix VI: Refining Capacity in Canada (as of December 1993)

			m³/day
ATLANTIC REGION			
Nfld Refining	Come-By-Chance	Nfld	16700
Ultramar	Halifax	NS	3500
Irving Oil	Saint John	NB	27700
Esso Petroleum	Dartmouth	NS	13100
QUEBEC REGION			
Petro-Canada	Montreal	Que	14300
Shell Canada	Montreal	Que	19070
Ultramar	St Romuald	Que	19800
ONTARIO REGION			
Esso Petroleum	Nanticoke	Ont	16900
Esso Petroleum	Sarnia	Ont	19310
Petro-Canada[1]	Clarkson	Ont	0
Petro-Canada	Oakville	Ont	12800
Polysar	Sarnia	Ont	17000
Shell Canada	Sarnia	Ont	11280
Suncor	Sarnia	Ont	11200
PRAIRIE REGION			
Co-Op/NewGrade	Regina	Sask	7180
Moose Jaw Asphalt	Moose Jaw	Sask	2110
Esso Petroleum	Edmonton	Alta	26200
Petro-Canada	Edmonton	Alta	19310
Husky	Lloydminster	Alta	3650
Parkland	Bowden	Alta	950
Shell Canada	Scotford	Alta	10900
Esso Petroleum	Norman Wells	NWT	510
BRITISH COLUMBIA REGION			
Chevron	Burnaby	BC	7150
Esso Petroleum[2]	Ioco	BC	7200
Husky	Prince George	BC	1530
TOTAL CANADIAN CAPACITY			**289350**

[1][1]Petro-Canada Clarkson refinery operates to produce lubricating oils using intermediate feedstocks.

[2]Esso Petroleum announced Ioco, B.C. refinery closure for mid-94.

Appendix VII: International and Domestic Crude Oil Prices

	US$/bbl							
	At Source			At Chicago			At Montreal	
	Cdn Par	Brent	WTI NYMEX	Cdn Par	Brent	WTI NYMEX	Cdn Par	Brent
Jan 1992	17.61	18.18	18.82	18.91	19.87	19.42	19.22	19.64
Feb	17.77	18.11	19.01	19.06	19.76	19.60	19.36	19.51
Mar	17.63	17.60	18.95	18.92	19.17	19.55	19.21	18.99
Apr	19.03	18.85	20.26	20.32	20.44	20.85	20.61	20.11
May	19.87	19.83	21.00	21.24	21.46	21.59	21.57	21.19
June	21.29	21.19	22.36	22.66	22.79	22.96	22.99	22.53
July	20.65	20.23	21.74	22.02	21.89	22.34	22.99	21.61
Aug	20.24	19.79	21.29	21.60	21.47	21.88	21.94	21.15
Sept	21.07	20.21	21.92	22.19	21.87	22.51	22.38	21.55
Oct	20.82	20.34	21.71	21.94	22.04	22.30	22.12	21.72
Nov	19.30	19.22	20.36	20.41	21.00	20.96	20.59	20.65
Dec	18.17	18.22	19.43	19.27	19.99	20.03	19.45	19.72
Av. 1992	19.45	19.31	20.57	20.71	20.98	21.17	21.04	20.70
Jan 1993	17.43	17.39	19.07	18.67	19.14	19.67	18.98	18.98
Feb	18.56	18.48	20.07	19.82	20.19	20.67	20.12	20.05
Mar	18.65	18.80	20.36	19.91	20.50	20.95	20.22	20.39
Apr	18.68	18.65	20.33	19.93	20.33	20.92	20.23	20.24
May	18.42	18.50	19.99	19.66	20.18	20.59	19.97	20.10
June	17.77	17.66	19.13	19.01	19.33	19.73	19.31	19.29
July	16.37	16.83	17.90	17.62	18.61	18.49	17.92	18.36
Aug	16.49	16.74	18.01	17.72	18.39	18.61	18.01	18.15
Sept	15.98	16.00	17.53	17.20	17.65	18.13	17.48	17.44
Oct	16.74	16.60	18.17	17.94	18.36	18.77	18.23	18.09
Nov	15.26	15.27	16.72	16.48	17.03	17.32	16.77	16.77
Dec	13.02	13.66	14.53	14.22	15.33	15.13	14.56	15.19
Av. 1993	16.95	17.05	18.48	18.18	18.75	19.08	18.48	18.59

Appendix VIII: Average Regular Unleaded Gasoline Prices (Self-Serve)

	1992	1993			
	Dec. 31	**Mar. 30**	**June 29**	**Sep. 28**	**Dec. 28**
			cents per litre		
St John's (Nfld)	56.8	56.4	59.0	56.3	51.0
Charlottetown	58.5	56.5	56.0	56.0	53.1
Halifax	52.9	49.6	53.9	51.3	48.6
Saint John (N.B.)[1]	55.1	55.2	56.8	54.9	50.7
Montreal	59.8	58.0	61.7	56.1	53.7
Toronto	52.2	49.4	50.0	52.8	45.5
Winnipeg	53.9	51.9	52.9	50.9	49.9
Regina	56.9	48.9	48.9	53.9	54.9
Calgary	43.6	42.3	47.6	47	43.3
Vancouver	55.9	52.9	54.4	56.4	50.1
Average	**54.3**	**51.8**	**54.1**	**53.4**	**49.0**
Consumption taxes include:					
Federal	11.9	11.8	11.9	11.9	11.6
Provincial	13.9	14.0	14.2	14.3	14.4

[1] Full-Serve

Appendix IX: Consumption Taxes on Petroleum Products (as of December 1993)

	Ad valorem		Gasoline			Diesel
	Mogas	Diesel	Reg UL	Mid UL	Prem UL	
	%		cents per litre			
Federal Taxes						
Estimated GST (7%)			3.1	3.5	3.7	3.3
Excise			8.5	8.5	8.5	4.0
Provincial Taxes						
Newfoundland[1]			15.7	15.7	15.7	17.6
Prince Edward Island	24	27	11.2	11.2	11.2	11.6
Nova Scotia	28.8	36.2	12.8	12.8	12.8	15.1
New Brunswick			10.7	10.7	10.7	13.7
Quebec[2]			18.5	18.8	19.2	16.6
Ontario			14.7	14.7	14.7	14.3
Manitoba			11.5	11.5	11.5	10.9
Saskatchewan			15.0	15.0	15.0	15.0
Alberta			9.0	9.0	9.0	9.0
British Columbia[3]			11.0	11.0	11.0	11.5
Yukon			6.2	6.2	6.2	7.2
Northwest Territories[4]	17		9.6	9.6	9.6	8.2

[1] The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay, Labrador.
[2] Reduced by varying amounts in certain remote areas and within 20 kilometres of the provincial and U.S. borders.
[3] Additional transit tax of 4.0 cents per litre in Vancouver.
[4] Ad valorem tax on diesel is 85% of gasoline tax.